



For a Strong Energy



Rex Energy Corporation

Annual Report

2011

In For The Long Haul

DEAR FELLOW SHAREHOLDERS,

was a year of tremendous growth and successful execution for Rex Energy. We capitalized on the momentum we gained in 2010 – expanding our drilling program in the Appalachian Basin, increasing production in our legacy fields in the Illinois Basin, and strategically adding attractive acreage in our core operating areas. In the midst of challenging conditions for exploration and development, and continuing volatility in the commodities markets, we remained critically focused on one thing – the execution of our business strategy. That focus produced some impressive results. We increased our average daily production rates by 92% and our proved reserves by 82% over 2010 levels. We refined our drilling and fracture stimulation techniques, resulting in significantly higher EURs for our Marcellus projects. We successfully completed our ASP Pilot in the Middagh Unit and booked proved reserves on two of our ASP projects. We strategically assessed our asset base and acted decisively to realign our resources to support development projects we believe will add shareholder value for years to come. Lastly, mindful of the current low natural gas price environment, we maintained our disciplined approach to hedging, helping us to manage our price risk and stabilize our cash flows – and positioning us for continued execution in 2012.

2011 HIGHLIGHTS

We entered 2011 in a position of strength and capitalized on this advantage to execute our drilling plans in the Appalachian Basin. During the year, we drilled or participated in the drilling of 58 wells in the Marcellus and Utica Shales, with 31 of these wells in our operated areas. We placed 51 wells into service – more than tripling our number of producing wells in the Marcellus Shale from 2010. We continued to seek and identify desirable opportunities to enhance our acreage portfolio, ultimately acquiring what we believe will be a strategic position in the emerging, liquids rich Utica Shale play in eastern Ohio. We successfully brought our first cryogenic processing facility in Butler County up to its capacity and we drew on the capabilities of our operating partners in our non-operated areas to increase our natural gas and natural gas liquids production.

We continued to leverage operational efficiencies in our Butler County area, using our concentrated acreage position to reduce drill rig movement, drilling time, and gathering line construction costs. We expect these savings to translate into lower operating and drilling costs, ultimately increasing rates of return for our Company and our shareholders.

As part of our strategic evaluation of our asset base, during 2011 we tested and ultimately proved the presence of two more producing horizons within our Butler County acreage, in addition to the Marcellus Shale. We successfully drilled and tested one well in the Utica Shale and another in the Burkett formation of the Upper Devonian Shale, and we were very encouraged by the test results. The addition of two producing horizons gives us the flexibility to select zones based on a desired production portfolio. We expect this to further enhance our drilling synergies as we will have the ability to drill three separate zones from one location.

In our Illinois Basin, the hard work and perseverance of our engineering team came to fruition with the booking of proved reserves in our Middagh and Perkins-Smith ASP project areas. We conducted a successful ASP pilot in the Middagh Project Area, which proved the viability of these tertiary recovery projects. As of the writing of this letter, we believe we are the only company in America to have successfully applied this specific ASP technology, and we remain excited about the potential use of ASP recovery methods in the future.

As a result of our focused execution, we achieved a production rate of 49.2 MMcfe per day by the end of the year, which was 116% above our production rate at the end of 2010. Our production growth continued throughout the year, with the fourth quarter of 2011 representing our fifth consecutive quarter of double digit production growth.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

SEC Mail Processing

Section

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

MAY 14 2012

For the fiscal year ended December 31, 2011

Commission file number: 001-33610

Washington DC

REX ENERGY CORPORATION 405

(Exact name of registrant as specified in its charter)

Delaware (State or other Jurisdiction of Incorporation or Organization) 20-8814402 (I.R.S. employer identification number)

476 Rolling Ridge Drive, Suite 300 State College, Pennsylvania 16801 (Address of Principal Executive Offices) (Zip Code) (814) 278-7267

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class

Name of each exchange on which registered

Common Stock, \$.001 par value per share

The NASDAQ Global Market

Securities registered pursuant to Section 12(g) of the Act:

	None								
Act.	Indicate by Yes	check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities No ⊠							
Act.	Indicate by Yes	check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the No \boxtimes							
Secu such	irities Excha	check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the ange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file at (2) has been subject to such filing requirements for the past 90 days. Yes No							
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files. Yes \boxtimes No \square									
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.									
smal Rule	ler reporting	check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a g company. See definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in e Exchange Act. (check one):							
	Large Acce	elerated filer Accelerated filer Non-accelerated filer Smaller reporting company							
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes \(\sigma\) No \(\otimes\)									
	The aggreg	ate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2011 was							

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2011 was \$362,511,918. This amount is based on the closing price of the registrant's common stock on the NASDAQ Global Market on that date. Shares of common stock beneficially held by executive officers and directors of the registrant are not included in the computation. This determination of affiliate status is not necessarily a conclusive determination for other purposes.

52,902,996 common shares, \$.001 par value, were outstanding on March 9, 2012.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for its 2012 Annual Meeting of Stockholders to be held on May 10, 2012, are incorporated by reference herein in Items 10, 11, 12, 13 and 14 of Part III of this report.

REX ENERGY CORPORATION

FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2011

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CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING STATEMENTS

Some of the information, including all of the estimates and assumptions, in this report contain forward-looking statements within the meaning of Sections 27A of the Securities Act of 1933, as amended, and 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this report, including, but not limited to, statements regarding our future financial position, business strategy, budgets, projected costs, savings and plans, objectives of management for future operations, legal strategies, and legal proceedings, are forward-looking statements. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "may", "will", "expect", "intend", "estimate", "anticipate", "believe", or "continue" or the negative thereof or variations thereon or similar terminology.

These forward-looking statements are subject to numerous assumptions, risks, and uncertainties. Factors that may cause our actual results, performance, or achievements to be materially different from those anticipated in forward-looking statements include, among others, the following:

- uncertainties regarding economic conditions in the United States and globally;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- domestic and global supply and demand for oil and natural gas;
- sustained or further declines in the prices we receive for oil and natural gas;
- the effects of government regulation, permitting, and other legal requirements;
- environmental risks;
- the geologic quality of our properties with regard to, among other things, the existence of hydrocarbons in economic quantities;
- uncertainties about the estimates of our oil and natural gas reserves;
- our ability to increase our production of oil and natural gas income through exploration and development;
- our ability to successfully apply horizontal drilling techniques and tertiary recovery methods;
- the number of well locations to be drilled, the cost to drill, and the time frame within which they will be drilled;
- the effects of adverse weather on operations;
- drilling and operating risks;
- the ability of contractors to timely and adequately perform their drilling, construction, well stimulation, completion and production services;
- the availability of equipment, such as drilling rigs and and related equipment and tools;
- changes in our drilling plans and related budgets;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity;
- the availability of gathering and transportation pipelines and processing and other midstream services;
- uncertainties associated with our legal proceedings and their outcome; and
- other factors discussed under "Risk Factors" in Item 1A of this report.

Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by such statements. You are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date of this report. Other unknown or unpredictable factors may cause actual results to differ materially from those projected by the forward-looking statements. Most of these factors are difficult to anticipate and may be beyond our control. Unless otherwise required by law, we undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

All forward-looking statements attributable to us are expressly qualified in their entirety by these cautionary statements.

SPECIAL NOTE REGARDING THE REGISTRANT

In this report, we refer to certain companies—Douglas Oil & Gas Limited Partnership, Douglas Westmoreland Limited Partnership, Midland Exploration Limited Partnership, New Albany—Indiana, LLC, PennTex Resources, L.P., PennTex Resources Illinois, Inc., Rex Energy Limited Partnership, Rex Energy II Limited Partnership, Rex Energy III LLC, Rex Energy IV, LLC, Rex Energy II Alpha Limited Partnership, Rex Energy Operating Corp. and Rex Energy Royalties Limited Partnership—collectively as the "Predecessor Companies." Simultaneously with the consummation of our initial public offering of common stock, through a series of mergers and reorganization transactions, which we refer to as the "Reorganization Transactions," Rex Energy Corporation acquired all of the outstanding equity interests of the Predecessor Companies. Unless otherwise indicated, all references to "Rex Energy Corporation," "the Company", "our," "we," "us" and similar terms refer to Rex Energy Corporation and its subsidiaries together with the Predecessor Companies, after giving effect to the Reorganization Transactions.

Beginning on page 134 of this report, we have included a glossary of oil and natural gas terms used throughout this report.

PART I

ITEM 1. BUSINESS

General

We are an independent oil and gas company operating in the Appalachian Basin and Illinois Basin. In the Appalachian Basin, we are focused on our Marcellus Shale drilling projects and Utica Shale and Upper Devonian Shale exploration activities. In the Illinois Basin, we are focused on the implementation of enhanced oil recovery on our properties as well as conventional oil production. We pursue a balanced growth strategy of exploiting our sizable inventory of high potential exploration drilling prospects while actively seeking to acquire complementary oil and natural gas properties.

We were incorporated in the state of Delaware on March 8, 2007. Our common stock currently trades on the NASDAQ Global Market under the symbol "REXX". The information set forth in this report is exclusive of our discontinued operations related to the Southwest Region and DJ Basin properties, unless otherwise noted, which are classified as Discontinued Operations on our Consolidated Statements of Operations and Assets Held for Sale on our Consolidated Balance Sheets.

At December 31, 2011, our estimated proved reserves had the following characteristics:

- 366.2 Bcfe;
- 74.9% natural gas and 25.1% crude oil and natural gas liquids ("NGLs");
- 47.3% proved developed; and
- a reserve life index of approximately 26 years (based upon 2011 production).

At December 31, 2011, we operated approximately 2,117 wells, which include approximately 517 disposal and injection wells. For the quarter ended December 31, 2011, we produced an average of 49.2 net MMcfe per day, composed of approximately 69.5% natural gas and 30.5% oil and NGLs.

We are one of the largest oil producers in the Illinois Basin, with average net production of 1,900 barrels of oil per day in 2011. In addition to our developmental shallow oil drilling in the Illinois Basin, we are in the process of implementing an enhanced oil recovery project, or EOR project, in the Lawrence Field in Lawrence County, Illinois, which we refer to as our Lawrence Field ASP Flood Project. During 2010, we commenced chemical injection into our 15-acre Middagh ASP pilot unit. During 2011, we received initial and peak production response from the project and production levels have begun a gradual decline. The successful response from the pilot project resulted in the assignment of 107.6 MBbls of estimated proved developed non-producing reserves to our next planned unit, the Perkins-Smith.

In the Appalachian Basin during 2011, we averaged net production of approximately 27.6 MMcfe per day of natural gas and NGLs. In 2011, we grew our reserves and production in the region primarily through Marcellus Shale drilling projects, while also drilling one successful test well into the Utica Shale and an additional successful test well to the Burkett Shale. As of December 31, 2011, we controlled approximately 129,200 gross (66,400 net) acres, which includes both developed and undeveloped acreage, in areas of Pennsylvania that we believe are prospective for Marcellus Shale exploration and approximately 105,300 gross (69,200 net) acres, which includes both developed and undeveloped acreage, in Pennsylvania and Ohio that we believe are prospective for Utica Shale exploration.

Our total operating revenue for the year ended December 31, 2011 was \$114.6 million. Revenue was derived from \$111.9 million in oil, natural gas and NGL sales and \$2.7 million in other revenue.

For the year ended December 31, 2011, we drilled 64.0 gross (34.2 net) wells, which includes one gross (one net) well drilled in connection with our Lawrence Field ASP Flood Project, and excludes wells drilled in

connection with the DJ Basin for which we have entered a plan to sell and have thus classified the assets as held for sale. Excluding those wells drilled in connection with our ASP project, the wells drilled in 2011 include 36.0 gross (17.1 net) wells that were productive and 27.0 gross (16.1 net) wells that are awaiting completion and are expected to be productive during the first quarter of 2012. The larger inventory of wells awaiting completion is primarily attributable to processing capacity restraints in our Butler County, Pennsylvania area of operations.

The following table sets forth selected data concerning our continuing operations, and our production, estimated proved reserves and undeveloped acreage in our two operating regions for the periods indicated:

Basin/Region	Annual 2011 Average Daily Mcfe ¹	Total Proved Bcfe (as of December 31, 2011)	Percent of Total Proved Bcfe	PV-10 (as of December 31, 2011) (in millions) ²	Undeveloped Acres (as of December 31, 2011) ³
Illinois Basin	11,398	49.1	13.4%	\$209.5	178
Appalachian Basin	27,560	317.1	86.6%	330.1	69,373
Total	38,958	366.2	100.0%	\$539.6	69,551

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Our Competitive Strengths

We believe our strengths provide us with significant competitive advantages and position us to successfully execute our business and growth strategies.

Our Appalachian Basin operations are strategically focused in highly desirable areas. We have a significant presence in the Marcellus Shale, one of the leading unconventional plays in North America, and have secured what we believe to be an advantageous position in the Utica Shale. As of December 31, 2011, we held approximately 66,400 net acres in the Marcellus Shale and approximately 62,400 net acres in the Utica Shale, with approximately 44,100 acres prospective for both formations. Our acreage positions are tightly concentrated, which we believe will enable us to achieve greater efficiencies in our drilling and completion operations than our competitors. (Please see "Item 2. Properties—Appalachian Basin" for additional information.)

We have a sizeable inventory of lower-risk development opportunities. As of December 31, 2011, we had an inventory of 22 gross (13.4 net) wells drilled and awaiting completion in our core operations area in the Appalachian Basin, with two gross (1.4) net wells completed and awaiting pipeline infrastructure. Our 2012 drilling program provides for the drilling of an additional 15 wells in locations we believe to be similarly prospective for liquids-rich production. To date, we have achieved a 100% success rate on our drilling program in this area of our operations. We believe that our strong operating history and strategic location of potential drilling sites will continue to provide us with further low-risk development opportunities in this area.

Oil and natural gas liquids are converted at the rate of one BOE to six Mcfe.

Represents the present value, discounted at 10% per annum (PV-10), of estimated future net cash flows before income tax of our estimated proved reserves. PV-10 is a non-GAAP financial measure because it excludes the effects of income taxes and asset retirement obligations. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as defined under GAAP. At December 31, 2011, our standardized measure was \$413.9 million. For an explanation of why we show PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flows, please read "Selected Financial and Operating Data—Non-GAAP Financial Measures." Please also read "Risk Factors—Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves."

Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage includes estimated proved reserves.

We have attractive growth opportunities in both our Appalachian and Illinois Basin properties. We believe that a significant portion of our Butler County, Pennsylvania acreage is prospective for three producing zones, the Upper Devonian Shale, the Marcellus Shale, and the Utica Shale. In our Illinois Basin properties, we are pursuing tertiary recovery of oil through our 15-acre Middagh Unit ASP pilot and expanded 58-acre Perkins Smith Unit ASP program, and, as of December 31, 2011, have booked proved reserves on these units at 13% of pore volume. We believe these results support our ability to increase oil production through the ASP program. We plan to further expand our ASP efforts and continue our evaluation of potential flood units, with the intention of strategically focusing on those that we believe demonstrate the greatest probability of success. (Please see "Item 2. Properties—Appalachian Basin" and Item 2. Properties—Illinois Basin—Lawrence Field ASP Flood Project" for additional information.)

Market Leader in the Illinois Basin: We are one of the largest oil producers and a market leader in the Illinois Basin. This enables us to realize a current premium over the basin-posted prices on our oil production with a competitive cost structure due to economies of scale. This scale also provides us with a unique local knowledge of the basin. We believe these advantages may enhance our ability to continue making strategic acquisitions in the basin.

Liquids-Rich Exposure: A substantial portion of our acreage holdings are in liquids-rich areas prospective for oil, condensate and NGL production. As of December 31, 2011, our holdings prospective for liquids-rich production accounted for approximately 82.6% of our total net acreage.

Business Strategy

Our strategy is to increase stockholder value by profitably increasing our reserves, production, cash flow and earnings. The following are key elements of our strategy:

Employ Technological Expertise: Our strategy is to utilize and expand the technological expertise that has enabled us to achieve a drilling success rate of approximately 95.7% over the last three years and has helped us improve operations and enhance field recoveries. When excluding operations from the DJ Basin, our success rate increases to 98.2%. We intend to continue to apply this expertise to our proved reserve base and our development projects.

Develop Our Existing Properties: Our focus is to develop our asset base, including:

- our Lawrence Field ASP Flood Project in Illinois;
- our Marcellus Shale play with approximately 129,200 gross (66,400 net) acres;
- our Utica Shale play with approximately 105,300 gross (69,200 net) acres; and
- our Burkett Shale play (an Upper Devonian Shale) with approximately 67,200 gross (44,800 net) acres.

Pursue Strategic Acquisitions and Joint Ventures: We plan to continue to acquire and lease additional oil and natural gas properties in our core areas of operation. We believe that our strong history of acquisitions, leading position in the Illinois Basin, success in the Marcellus Shale and technical expertise situate us well to attract joint venture partners and pursue strategic acquisitions.

Focus on Operations: We intend to focus our future acquisition and leasing activities on properties where we have a significant working interest and can operate the property to control and implement the planned exploration and development activity.

Reduce Per Unit Operating Costs Through Economies of Scale and Efficient Operations: As we continue to increase our oil and natural gas production and develop our existing properties, we believe that our per unit production costs can benefit from increased production in lower cost operations and through better use of our existing infrastructure over a larger number of wells.

Maintain Flexibility: Because of the volatility of commodity prices and the risks involved in our industry, we believe in remaining flexible in our capital budgeting process. When appropriate, we may defer

capital projects to seize an attractive acquisition opportunity or reallocate capital towards projects where we believe we can generate higher than anticipated returns. We also believe in maintaining a strong balance sheet and using commodity hedging. This allows us to be more opportunistic in lower price environments as well as providing more consistent financial results.

Significant Accomplishments in 2011

During 2011, our significant accomplishments included:

- Long-term natural gas sales, gathering and processing agreements: During 2011, we entered into four separate firm agreements covering natural gas sales, gathering and processing in the Appalachian Basin. In Butler County, Pennsylvania, we entered into a natural gas sales agreement with BP Energy Company reserving minimum volumes of 17,500 MMBtu per day beginning March 1, 2012 and increasing to 59,500 MMBtu per day on January 1, 2013 and ending on December 31, 2022. In Ohio, we entered into gathering and processing agreements with Dominion East Ohio and Dominion Natrium, LLC, respectively, under which we have agreed to provide 15.0 MMcf per day for transportation and processing. We anticipate the gathering agreement to take effect on or around October 1, 2012 and the processing agreement to commence on or around December 1, 2012. Both agreements have 10-year primary terms. Also in Ohio, we entered into a natural gas sales agreement for firm takeaway with BP Energy Company reserving minimum volumes of 14,000 MMBtu per day. The agreement is expected to commence in early 2014 and run coterminous with the gathering and processing agreement with Dominion Natrium, LLC.
- Horizontal drilling success: In our operated areas of the Appalachian Basin we drilled 31.0 gross (19.8 net) wells and placed 21.0 gross (13.9 net) wells into service. Additionally, we participated in the drilling of 26.0 gross (10.4 net) wells and placed 30.0 gross (12.0 net) wells into service in our non-operated areas of the Appalachian Basin. As of December 31, 2011, we had 25.0 gross (14.1 net) wells awaiting completion or pipeline infrastructure between our operated and non-operated areas in the Appalachian Basin.
- **ASP reserves:** We received peak production response from our 15-acre Middagh ASP pilot unit during 2011, increasing oil cuts from 1% prior to chemical injection to approximately 12%, with several wells in the unit peaking at oil cuts of 17%. This success led to the booking of proved developed non-producing reserves of 107.6 MBls.
- Ohio acreage acquisitions: We began an exploration program in Ohio targeting the liquids-rich window of the Utica Shale. As of December 31, 2011, we had leasehold or leasehold commitments of approximately 15,000 gross acres.
- Decrease in lease operating expenses: We have decreased our lease operating expenses, on a per unit of production basis, for three consecutive years, from \$4.66 per Mcfe in 2008 to \$2.33 per Mcfe in 2011.
- Drilled test wells to the Burkett and Utica formations: During 2011, we drilled one test well to the
 Burkett Shale formation and an additional test well to the Utica Shale formation on our operated Butler
 County, Pennsylvania acreage. These two tests confirmed the existence of two additional commercially
 viable zones as we recorded estimated proved reserves for both of these wells.
- **Production growth:** Due to our Marcellus Shale drilling program, we increased our natural gas and NGL production by 188.6% and 644.0%, respectively, over 2010.
- Reserves growth: Our estimated proved reserves in the Appalachian Basin, which consist of 100% natural gas and NGLs, increased approximately 107.5% from 2010 year-end estimates.
- Permit received for second cryogenic gas processing plant: During the fourth quarter of 2011, our midstream joint venture, Keystone Midstream Services, LLC ("Keystone Midstream"), obtained all

- necessary permits to begin construction of the Bluestone cryogenic gas processing plant in Butler County, Pennsylvania. The Bluestone Plant is expected to have approximately 50.0 MMcf per day of gross throughput capacity and is anticipated to be commissioned during the second quarter of 2012.
- Continued Expansion of Drilling Inventory: To continue to grow, the size of our prospect inventory must remain large. As of December 31, 2011, we controlled approximately 129,200 gross (66,400 net) acres prospective for the Marcellus Shale play, 106,100 gross (69,900 net) acres prospective for the Utica Shale play and 67,200 gross (44,800 net) acres prospective for the Burkett Shale play. In addition, as of December 31, 2011, we had proved undeveloped ("PUD") reserves of approximately 192.9 Bcfe in the Appalachian Basin, comprising 90.0 gross PUD well locations.

Plans for 2012

Our budgeted capital spending for 2012 is approximately \$155.3 million. Our 2012 capital budget contemplates the drilling of approximately 15.0 gross (11.0 net) horizontal Marcellus, Utica and Upper Devonian Shale wells in Butler County, Pennsylvania and an additional seven gross (three net) horizontal wells in the joint venture project areas with WPX Energy. In our Carroll County, Ohio operating area, we are expecting to drill three gross (two net) horizontal Utica Shale wells.

Other operational plans for 2012 include the construction and commissioning of a second gas processing facility in Butler County, Pennsylvania, and the expansion of our enhanced oil recovery projects in Lawrence County, Illinois. The following table summarizes our actual 2011 and our budgeted 2012 capital expenditures. The estimated capital expenditures are dependent on a number of factors, including industry conditions and our drilling success, and are subject to change. We do not attempt to budget for future acquisitions of proved oil and gas properties.

For the Veers Ended

	Decen	ears Ended iber 31, ousands)
	2011 (Actual)	2012 (Estimated)
Capital Expenditures		
Illinois Basin Drilling & Facility	\$ 7,264	\$ 10,275
Illinois Basin Enhanced Oil Recovery	4,022	8,424
Illinois Basin Other	2,010	2,396
Appalachian Basin Drilling & Facility	158,982	123,656
Appalachian Basin Midstream ¹	23,204	10,000
Appalachian Basin Other	5,082	
DJ Basin Drilling & Facility ²	22,052	_
DJ Basin Other ²	106	_
Other Corporate Expenditures	1,016	530
Total Capital Expenditures ³	\$223,738	\$155,281

Includes contributions to equity method investments and consolidated subsidiaries.

All assets associated with our DJ Basin operations were classified as held for sale as of December 31, 2011.

We do not attempt to budget for future acquisitions of proved and unproved oil and gas properties. Capital expenditures for the acquisition of unproved properties for the year ended December 31, 2011 totaled approximately \$78.7 million.

Production, Revenues and Price History

The following table sets forth information regarding oil and gas production and revenues from continuing operations for the last three years:

	Production and Revenue by Regi For the Years Ended December 31, (\$ in thousands)				egion	
		2011		2010	_	2009
Appalachian Region:						
Revenue	\$	48,444	\$	14,652	\$	6,671
Oil Production (Bbls)		1,043		108		358
Natural Gas Production (Mcf)		8,912,250	3	3,088,598	1	,510,500
NGL Production (Bbls)	_	190,151	_	25,559		7,750
Total Production (Mcfe) ¹		10,059,414	3	3,242,600	1	,559,148
Oil Average Sales Price	\$	76.91	\$	41.63	\$	50.28
Natural Gas Average Sales Price	\$	4.28	\$	4.46	\$	4.28
NGL Average Sales Price	\$	53.66	\$	33.60	\$	24.90
Average Production Cost per Mcfe ³	\$	1.10	\$	1.13	\$	1.33
Illinois Region:	,					
Revenue	\$	63,435	\$	52,572	\$	41,863
Oil Production (Bbls)	•	693,409		691,466	•	719,652
Natural Gas Production (Mcf)		_				
NGL Production (Bbls)						_
Total Production (Bbls)	_	693,409	_	691,466		719,652
Oil Average Sales Price	\$	91.48	\$	76.03	\$	58.17
Natural Gas Average Sales Price	\$	_	\$	_	\$	
NGL Average Sales Price	\$		\$		\$	_
Average Production Cost per Bbl ³	\$	29.36	\$	29.68	\$	27.02
Total Company ²						
Revenue	\$	111,879	\$	67,224	\$	48,534
Oil Production (Bbls)	φ	694,452	φ	691,574	Ф	720,010
Natural Gas Production (Mcf)		8,912,250	3	5,088,598	1	,510,500
NGL Production (Bbls)		190,151		25,559	-	7,750
	_					
Total Production (Mcfe) ¹ Oil Average Sales Price		14,219,868		7,391,396 76.03		5,877,060 58.17
Natural Gas Average Sales Price	\$ \$	91.35 4.28	\$ \$	4.46	\$ \$	4.28
NGL Average Sales Price	\$ \$	53.66	\$ \$	33.60	\$ \$	24.90
Average Production Cost per Mcfe ³	\$	2.30	\$	33.00	\$ \$	3.66
	Ψ	2.50	Ψ	J.4J	Ψ	5.00

Oil and NGLs are converted at the rate of one BOE to six Mcfe.

Competition

The oil and gas industry is intensely competitive, particularly with respect to the acquisition of prospective oil and natural gas properties and reserves. Our ability to effectively compete is dependent on our geological, geophysical and engineering expertise and our financial resources. We must compete against a substantial number of major and independent oil and natural gas companies that have larger technical staffs and greater financial and operational resources than we do. Many of these companies not only engage in the acquisition,

² There were no revenues or production from our DJ Basin operations during 2010.

³ Excludes ad valorem and severance taxes.

exploration, development and production of oil and natural gas reserves, but also have refining operations, market refined products and generate electricity. We also compete with other oil and natural gas companies to secure drilling rigs and other equipment and services necessary for drilling and completion of wells. Consequently, equipment and services may be in short supply from time to time. Additionally, it is difficult to attract and retain employees, particularly those with expertise in high demand areas.

Employees

As of December 31, 2011, we had 204 full-time employees, 123 of whom were field personnel. No employees are covered by a labor union or other collective bargaining arrangement. We believe that our relations with our employees are good. We regularly utilize independent consultants and contractors to perform various professional services, particularly in the areas of drilling, completion, field services, oil and gas leasing and on-site production operation services.

Marketing and Customers

We market nearly all of our oil production from the properties that we operate in the Illinois Basin for both our interest and that of the other working interest owners and royalty owners. For properties that we operate in the Appalachian Basin, our natural gas production is currently marketed by WPX Energy Marketing for our interest and that of the other working interest owners and royalty owners. During the fourth quarter of 2011, we entered into two new natural gas sales agreements. Under the first agreement with BP Energy Company ("BP Energy"), we have agreed to supply natural gas to BP Energy at certain delivery points in Pennsylvania. During the term of the sales agreement, which is expected to terminate December 31, 2022, we are obligated to provide to BP Energy, and BP Energy is obligated to purchase from us, a minimum monthly volume of natural gas equivalent to 17,500 MMBtu per day from March 1, 2012 to December 31, 2012 and 59,500 MMBtu per day after January 1, 2013. The price for baseload quantities of natural gas is determined by reference to the Dominion Transmission Inc.—Appalachia index price published in Platt's Inside FERC Gas Market Report for the month of delivery. Under the second agreement with BP Energy, we have agreed to supply natural gas to BP Energy in relation to anticipated Ohio production. During the term of the sales agreement, which is expected to terminate December 31, 2022, we are obligated to provide to BP Energy, and BP Energy is obligated to purchase from us, a minimum monthly volume of natural gas equal to 14,000 MMBtu per day. The price for baseload quantities of natural gas is determined by reference to the Dominion Transmission Inc.—Appalachia index price published in Platt's Inside FERC Gas Market Report for the month of delivery.

In the Illinois Basin, the majority of our oil is stored at well site tanks and sold to CountryMark Cooperative, LLP ("CountryMark"), a local refinery, currently at a premium to the basin-posted prices. We receive this premium due to our significant size in the basin relative to other local producers. Purchasers, including CountryMark, purchase our oil at our tank facilities and truck the oil to their refinery facilities. The revenue that we derived from our sales to CountryMark constituted approximately 56.2% of our oil and natural gas revenue from continuing operations for 2011. As such, we are currently significantly dependent on the creditworthiness of CountryMark. We have taken steps to monitor the creditworthiness of CountryMark, including obtaining a letter of credit corresponding to a significant portion of projected monthly revenue. For additional information, see "Risk Factors—We depend on a relatively small number of purchasers for a substantial portion of our revenue. The inability of one or more of our purchasers to meet their obligations or the loss of our market with CountryMark Cooperative, LLP, in particular, may adversely affect our financial results," in Item 1A of this report.

On December 30, 2009, we entered into a Master Crude Purchase Agreement (the "Master Crude Purchase Agreement") with CountryMark. The agreement was effective as of January 1, 2010. Under the terms of the agreement, we agreed to sell, supply and deliver to CountryMark, and CountryMark agreed to receive and purchase from us, crude oil pursuant to purchase and sale order confirmations that we and CountryMark may enter into from time to time. Under the agreement, until we enter into a confirmation with CountryMark, neither

party is under an obligation to purchase or sell any crude oil. The term of the Master Crude Purchase Agreement provides that the term will automatically be extended for additional one-year terms unless, prior to October 1 of each year, either party gives written notice to the other. We have entered into a confirmation with CountryMark, whereby CountryMark has agreed to purchase substantially all of the crude oil that we produce in 2012 in the Illinois Basin. However, as of December 31, 2011, we were not committed to any delivery levels with CountryMark or any other party. We also have an offload facility at a nearby crude oil pipeline that Marathon Oil Corp operates that has enabled us to diversify our purchasers in the Illinois Basin.

In the Appalachian Basin, our natural gas producing properties are located near existing pipeline systems and processing infrastructure. We transport the majority of our production over our own, or jointly owned, gathering lines to local distribution companies.

Through our joint venture with Keystone Midstream, we have constructed a high pressure gathering system and a cryogenic gas processing plant in Butler County, Pennsylvania. The cryogenic gas processing plant services our wells and third-party wells in areas that produce natural gas with a high BTU content. The cryogenic gas processing plant decreases the BTU level of the gas to appropriate levels for distribution through a standard sales line. The by-products of the cryogenic gas processing plant are natural gas liquids, which are marketed separately. Keystone Midstream is currently in the construction stage for a second cryogenic gas processing plant in Butler County, Pennsylvania.

Prices for oil and natural gas fluctuate widely based on, among other things, supply and demand. Supply and demand are influenced by a number of factors, including weather, foreign policy, industry practices and the U.S. and worldwide economic climate. Oil and natural gas markets have historically been cyclical and volatile in nature as a result of many factors that are beyond our control. There can be no assurance of what price we will be able to sell our oil and natural gas. Prices may be low when our wells are most productive, thereby reducing overall returns.

We enter into derivative transactions with unaffiliated third parties to achieve more predictable cash flows and to reduce our exposure to short-term fluctuations in oil and gas prices. For a more detailed discussion, see the information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Governmental Regulations

Our oil and natural gas exploration, production, and related operations are subject to extensive statutory and regulatory oversight by federal, state, tribal and local authorities. We must, for example, obtain drilling permits, post bonds for drilling, operating, and reclamation, and submit various reports. The following activities are also subject to regulation: the location of wells, the method of drilling completion and operating wells, secondary and enhanced oil recovery projects, notice to surface owners and third parties, the surface development, use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, temporary storage tank operations, air emissions from flaring, compression and access roads, the impoundment of water, the manner and extent of earth disturbances, air emissions, sour gas management, the disposal of fluids used in connection with operations, and the calculation and distribution of royalty payments and production taxes. We must also comply with statutes and regulations addressing conservation matters, including the size of drilling and spacing units, or proration units, the number of wells that may be drilled in an area, the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production. Failure to comply with any of these requirements can result in substantial monetary penalties or lease cancellation. Finally, in the past tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities that must be addressed before those activities can proceed. Moreover most states impose a production, ad valorem or severance tax with respect to production and sale of oil or natural gas within its jurisdiction.

The increasing regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our production rates. However, these burdens generally do not affect us differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production. Additional proposals or proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commision ("FERC"), and the courts. Implementation of such could increase the regulatory burden and potential for financial sanctions for non-compliance. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. We may be required to make significant expenditures to comply with governmental laws and regulations, which could have a material adverse effect on our business, financial condition and results of operations.

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 ("NGPA"), and the regulations promulgated thereunder by the FERC. In the past, the federal government has regulated the prices at which oil and gas could be sold. Deregulation of wellhead sales in the natural gas industry began with the enactment of the NGPA. In 1989, the Natural Gas Wellhead Decontrol Act was enacted, removing both price and non-price controls from natural gas sold in "first sales" no later than January 1, 1993. While sales by producers of natural gas, and all sales of crude oil, condensate and natural gas liquids currently can be made at uncontrolled market prices, Congress could reenact price controls in the future.

The FERC regulates interstate natural gas transportation rates and service conditions. Its regulations affect the marketing of natural gas produced by us, as well as the revenues that may be received by us for sales of such production. Since the mid-1980s, FERC has issued a series of orders, collectively, Order 636, that have significantly altered the marketing and transportation of natural gas. Order 636 mandated a fundamental restructuring of interstate pipeline sales and transportation service, including the unbundling by interstate pipelines of the sale, transportation, storage and other services such pipelines previously performed. One of FERC's purposes in issuing Order 636 was to increase competition within the natural gas industry. Generally, Order 636 has eliminated or substantially reduced the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation service, and has substantially increased competition and volatility in natural gas markets.

The price we receive from the sale of oil and natural gas liquids will be affected by the cost of transporting products to markets. Effective January 1, 1995, FERC implemented regulations establishing an indexing system for transportation rates for oil pipelines, which, generally, index such rates to inflation, subject to certain conditions and limitations. We are unable to predict the effect, if any, of these regulations on our intended operations. The regulations may, however, increase transportation costs or reduce well head prices for oil and natural gas liquids.

In August 2005, Congress enacted the Energy Policy Act of 2005 ("EPAct 2005"). Among other matters, the EPAct 2005 amends the Natural Gas Act ("NGA"), to make it unlawful for "any entity," including otherwise non-jurisdictional producers such as us to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. On January 20, 2006, the FERC issued rules implementing this provision. The rules make it unlawful in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit any such statement necessary to make the statements no misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the NGA up to \$1,000,000 per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sale or gathering, but does apply to activities or otherwise non-jurisdictional entities to the extent the activities

are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction which includes the reporting requirements under Order Nos. 704 and 720. It therefore reflects a significant expansion of FERC's enforcement authority. We have not been affected differently than any other producer of natural gas by this act.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection and the discharge of materials into the environment. These laws and regulations:

- require the acquisition of permits or other authorizations before construction, drilling and certain other of our activities;
- limit or prohibit construction, drilling and other activities on specified lands within wilderness and other protected areas; and
- impose substantial liabilities for pollution that may result from our operations;
- require the installation of pollution control equipment in connection with operations;
- place restrictions or regulations upon the use or disposal of the material utilized in on our operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;
- require remedial measures to mitigate pollution from former and ongoing operations, such as site restoration, pit closure and plugging of abandoned wells; and
- require the expenditure of significant amounts in connection with worker health and safety.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce environmental laws and regulations, and violations may result in fines, injunctions or even criminal penalties. Some states continue to adopt new regulations and permit requirements, which may impede or delay our operations or increase our costs. We believe that we are in substantial compliance with current applicable environmental laws and regulations, and, except for those matters described in "Item 3. Legal Proceedings," have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, the trend in environmental legislation and regulation generally is toward stricter standards, and we expect that this trend will continue. Changes in existing environmental laws and regulations or in interpretations of these laws and regulations could have a significant impact on us, as well as the oil and natural gas industry as a whole.

The following is a summary of the existing laws and regulations that could have a material impact on our business operations.

The Resource Conservation and Recovery Act, as amended ("RCRA"), and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration and production of crude oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial condition.

The Comprehensive Environmental, Response, Compensation, and Liability Act, as amended ("CERCLA"), and comparable state statutes impose strict liability on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at these sites. This liability may be joint and several and includes liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production, and produced water disposal operations for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been disposed of or released on or under the properties that we own or lease, or on or under other locations, including off-site locations, where these substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA, and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes or property contamination, or to perform remedial activities to prevent future contamination.

The Federal Water Pollution Control Act (the "Clean Water Act"), and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The EPA and delegated states have adopted regulations concerning the discharge of storm water runoff. These regulations require covered facilities to obtain individual permits or to seek coverage under a general permit. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The Clean Water Act also prohibits the unpermitted discharge of fill material into waters of the United States, including certain wetlands. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Our oil and natural gas exploration and production operations generate produced water as a waste material, which is subject to the disposal requirements of the Clean Water Act, the Safe Drinking Water Act ("SDWA"), or an equivalent state regulatory program. This produced water is disposed of by re-injection into the subsurface through disposal wells, treatment and discharge to the surface or in evaporation ponds. Whichever disposal method is used, produced water must be disposed of in compliance with permits issued by regulatory agencies, and in compliance with applicable environmental regulations. This water can sometimes be disposed of by discharging it under discharge permits issued pursuant to the Clean Water Act or an equivalent state program. Another common method of produced water disposal is subsurface injection in disposal wells. Such disposal wells are permitted under the Underground Injection Control program, ("UIC"), which is a program promulgated under the SDWA. EPA directly administers the UIC in some states and in others it is delegated to the states. To date, we believe that all necessary surface discharge or disposal wells in substantial compliance with such obtained permits and applicable laws and regulations.

The Federal Clean Air Act, and comparable state laws, regulates emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. On July 28, 2011, the EPA issued proposed rules that would subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques along with pit flaring of gas not sent to a gathering line. The

standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology, or MACT standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Final action on the proposed rules is expected no later than April 3, 2012. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and associated state laws and regulations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly reporting, waste handling, storage, transport, disposal, or cleanup requirements could materially adversely affect our operations and financial position, as well as those of the oil and gas industry in general. For example, recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress has from time to time considered climate change-related legislation to restrict greenhouse gas emissions. The ultimate outcome of this legislative initiative remains uncertain. Almost half o fthe states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although it is not possible at this time to predict whether or when the U.S. Congress may act on climate change legislation or how federal legislation may be reconciled with state and regional requirements, any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could require us to incur increased operating costs and could adversely affect demand for the oil, natural gas and NGLs that we produce.

In 2007, the U.S. Supreme Court held in Massachusetts, et al. v. EPA that greenhouse gas emissions may be regulated as an "air pollutant" under the federal Clean Air Act. On December 15, 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allowed the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Since 2009, the EPA has issued regulations that, among other things, require a reduction in emissions of greenhouse gases from motor vehicles and that impose greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. In addition, on September 22, 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010. On November 9, 2010 the EPA expanded its greenhouse reporting rule to include onshore petroleum and natural gas production, processing, transmission, storage, and distribution facilities. Under these rules, reporting of greenhouse gas emissions from such facilities is required on an annual basis, with reporting beginning in September 2012 for emissions occurring in 2011.

Although it is not possible at this time to predict whether proposed legislation or regulations will be adopted as initially written, if at all, or how legislation or new regulations that may be adopted to address greenhouse gas emissions would impact our business, any such future laws and regulations could result in increased compliance costs or additional operating restrictions. Any additional costs or operating restrictions associated with legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our business, financial condition and results of operation. In addition, these developments could curtail the demand for fossil fuels such as oil and gas in areas of the world where our customers operate and thus adversely affect demand for our products and services, which may in turn adversely affect our future results of operations.

Available Information

We maintain an internet website under the name "www.rexenergy.com." We make available, free of charge, on our website, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the Securities

and Exchange Commission ("SEC"). Our Corporate Governance Policy, the charters of the Audit Committee, the Compensation Committee and the Nominating and Governance Committee, and the Code of Ethics for directors, officers, employees and financial officers are also available on our website and in print to any stockholder who provides a written request to the Corporate Secretary at 476 Rolling Ridge Drive, Suite 300, State College, PA 16801.

We file annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934, as amended. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains an internet website that contains reports, proxy and information statements, and other information regarding issuers, including Rex Energy Corporation, that file electronically with the SEC. The public can obtain any document we file with the SEC at www.sec.gov. Information contained on or connected to our website is not incorporated by reference into this Form 10-K and should not be considered part of this report or any other filing that we make with the SEC.

ITEM 1A. RISK FACTORS

In evaluating our company, the factors described below should be considered carefully. The occurrence of one or more of these events could significantly and adversely affect our business, prospects, financial condition, results of operations and cash flows.

Risks Related to Our Company

Volatility in oil, NGL and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil, NGL and natural gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities, and therefore their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil, NGLs and natural gas;
- the condition of the U.S. and global economy;
- · the actions of certain foreign states;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil producing activities;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- production or pricing decisions made by the Organization of Petroleum Exporting Countries;
- weather conditions;
- availability of limited refining facilities in the Illinois Basin reducing competition and resulting in lower regional oil prices than in other U.S. oil producing regions;
- · technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil, NGL and natural gas prices may not only decrease our revenues on a per unit basis, but also may reduce the amount of oil, NGLs and natural gas that we can produce economically. The higher operating costs associated with many of our oil fields will make our profitability more sensitive to oil price declines. A sustained decline in oil, NGL or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Drilling for and producing oil, NGLs and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil, NGL and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil, NGL or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities

and present value of our reserves. Please see below for a discussion of the uncertainties involved in these processes. Our costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures could be materially and adversely affected by any factor that may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- unusual or unexpected geological formations;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- · equipment malfunctions, failures or accidents;
- unexpected operational events and drilling conditions;
- pipe or cement failures;
- casing collapses;
- lost or damaged oilfield drilling and service tools;
- loss of drilling fluid circulation;
- uncontrollable flows of oil, natural gas and fluids;
- fires and natural disasters;
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures, discharges of toxic gases
 or mishandling of fluids (including frac fluids) and underground migration issues;
- adverse weather conditions;
- · reductions in oil and natural gas prices;
- oil and natural gas property title problems; and
- market limitations for oil and natural gas.

If any of these factors were to occur with respect to a particular field, we could lose all or a part of our investment in the field, or we could fail to realize the expected benefits from the field, either of which could materially and adversely affect our revenue and profitability.

Prospects that we decide to drill may not yield oil, NGLs or natural gas in commercially viable quantities.

Our prospects are in various stages of evaluation. There is no way to predict with certainty in advance of drilling and testing whether any particular prospect will yield oil, NGLs or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable, particularly in light of the current economic environment. The use of seismic data and other technologies, and the study of producing fields in the same area, will not enable us to know conclusively before drilling whether oil, NGLs or natural gas will be present or, if present, whether oil, NGLs or natural gas will be present in commercially viable quantities. Moreover, the analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves.

Estimates of oil and natural gas reserves are inherently imprecise. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves. To prepare our proved reserve estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil, NGL and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil, NGL and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus supplement. In addition, we may adjust estimates of estimated proved reserves to reflect production history, results of exploration and development, prevailing oil, NGL and natural gas prices and other factors, many of which are beyond our control.

The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves.

We base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production;
- supply of and demand for oil and natural gas; and
- · changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from estimated proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for, and development, production and acquisition of, oil and natural gas reserves. For 2012, we have budgeted approximately \$155.3 million for capital expenditures for development and exploration activities in the Appalachian and Illinois Basins. To date, we have financed capital expenditures primarily with proceeds from bank borrowings, cash generated by operations, public stock offerings, sales of non-core assets and joint venture agreements. We intend to finance our future

capital expenditures with proceeds from bank borrowings, the sale of debt or equity securities, asset sales, cash flow from operations and current and new financing arrangements, such as joint ventures. Our cash flow from operations and access to capital is subject to a number of variables, including:

- · our estimated proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- our ability to extract NGLs from the natural gas we produce;
- the prices at which oil, NGLs and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues decrease as a result of lower oil, NGL and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may need to seek additional financing in the future. In addition, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our oil and natural gas reserves. Also, our senior credit facility and our second lien credit facility each contain covenants that restrict our ability to, among other things, materially change our business, approve and distribute dividends, enter into transactions with affiliates, create or acquire additional subsidiaries, incur indebtedness, sell assets, make loans to others, make investments, enter into mergers, incur liens, and enter into agreements regarding swap and other derivative transactions.

Our indebtedness could adversely affect our financial condition and our ability to operate our business.

As of December 31, 2011, outstanding borrowings under our senior credit facility and our second lien credit facility totaled \$225.0 million. We will incur additional debt from time to time, and such borrowings may be substantial. Our debt could have material adverse consequences to us, including the following:

- it may be difficult for us to satisfy our obligations, including debt service requirements under our credit agreements;
- our ability to obtain additional financing for working capital, capital expenditures, debt service requirements and other general corporate purposes may be impaired; and
- our ability to capitalize on business opportunities, and to react to competitive pressures, as compared to others in our industry, may be limited.

In addition, the agreements governing our senior credit facility and second lien term loan contain a number of significant covenants that place limitations on our activities and operations, including those relating to (i) creation of liens; (ii) hedging activities; (iii) mergers, acquisitions, asset sales and dispositions; (iv) payment of dividends; and (v) incurrence of additional indebtedness. Our credit agreements also require us to maintain compliance with specified financial ratios and satisfy certain financial condition tests. Our ability to comply with these ratios and financial condition tests may be affected by events beyond our control, and we cannot assure you that we will meet these ratios and financial condition tests. These financial ratio restrictions and financial condition tests could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable corporate activities.

The development of our proved undeveloped reserves in our areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 53% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2011. Development of these reserves may take longer and require higher levels of capital

expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our estimated proved reserves as unproved reserves.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending on reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs, which would adversely affect our business, financial condition and results of operations.

If we are unable to acquire adequate supplies of water for our Marcellus Shale drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities could be impaired.

We use between three and four million gallons of water per well in our Marcellus Shale well completion operations. Our inability to locate sufficient amounts of water, or dispose of water after drilling, could adversely impact our operations. Moreover, the adoption and implementation of new environmental regulations could result in restrictions on our ability to conduct certain operations such as hydraulic fracturing or the imposition of new requirements pertaining to the management and disposal of wastes generated by our operations, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. Furthermore, new environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may also increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could adversely affect our financial condition and results of operations.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and drilling and completion services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

We may, from time to time, encounter difficulty in obtaining, or an increase in the cost of securing, drilling rigs, equipment, services and supplies. In addition, larger producers may be more likely to secure access to such equipment and services by offering more lucrative terms. If we are unable to acquire access to such resources, or can obtain access only at higher prices, our ability to convert our reserves into cash flow could be delayed and the cost of producing those reserves could increase significantly, which would adversely affect our financial condition and results of operations.

Federal, state and local regulation of hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We commonly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In

addition, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

If our access to markets is restricted, it could negatively impact our production, our income and ultimately our ability to retain our leases. Our ability to sell our oil, NGLs, and natural gas and/or receive market prices for our oil, NGLs and natural gas may be adversely affected by pipeline and gathering system capacity constraints.

Market conditions or the unavailability of satisfactory oil, NGL and natural gas transportation arrangements may hinder our access to oil, NGL and natural gas markets or delay our production. The availability of a ready market for our oil, NGL and natural gas production depends on a number of factors, including the demand for and supply of oil, NGLs and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. Our productive properties may be located in areas with limited or no access to pipelines, thereby necessitating delivery by other means, such as trucking, or requiring compression facilities. Such restrictions on our ability to sell our oil, NGLs or natural gas may have several adverse effects, including higher transportation costs, fewer potential purchasers (thereby potentially resulting in a lower selling price) or, in the event we were unable to market and sustain production from a particular lease for an extended time, possibly causing us to lose a lease due to lack of production.

If drilling in the Marcellus Shale and other areas of the Appalachian Basin continues to be successful, the amount of natural gas being produced by us and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If this occurs, it will be necessary for new pipelines and gathering systems to be built. Because of the current economic climate, certain pipeline projects that are planned for these areas may not occur. In addition, capital constraints could limit our

ability to build intrastate gathering systems necessary to transport our gas to interstate pipelines. In such event, we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell natural gas production at significantly lower prices than those quoted on NYMEX or than we currently project, which would adversely affect our results of operations.

A portion of our natural gas, NGL and oil production in any region may be interrupted, or shut in, from time to time for numerous reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could temporarily adversely affect our cash flow.

Enhanced Oil Recovery ("EOR") techniques that we may use, such as our Alkali-Surfactant-Polymer flooding in the Lawrence Field, involve more risk than traditional waterflooding.

An EOR technique such as alkali-surfactant-polymer, or ASP, chemical injection involves significant capital investment and an extended period of time, generally a year or longer, from the initial phase of a pilot program until increased production occurs. The results of any successful pilot program may not be indicative of actual results achieved in a broader EOR project in the same field or area. Generally, surfactant polymer, including ASP, injection is regarded as involving more risk than traditional waterflood operations. The potential resources associated with our ASP project in the Lawrence Field are not considered estimated proved reserves. Our ability to achieve commercial production and recognize estimated proved reserves from our EOR projects is greatly contingent upon many inherent uncertainties associated with EOR technology, including ASP technology, geological uncertainties, chemical and equipment availability, rig availability and many other factors.

We cannot control activities on properties that we do not operate and are unable to control their proper operation and profitability.

We do not operate all of the properties in which we own an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, the operations of these properties. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors outside of our control, including the operator's:

- nature and timing of drilling and operational activities;
- · timing and amount of capital expenditures;
- · expertise and financial resources;
- · the approval of other participants in drilling wells; and
- · selection of suitable technology.

All of the value of our production and reserves is concentrated in the Illinois Basin and Appalachian Basin. Because of this concentration, any production problems or changes in assumptions affecting our proved reserve estimates related to these areas could have a material adverse impact our business.

For the year ended December 31, 2011, approximately 29% of our net production came from the Illinois Basin area and 71% came from the Appalachian Basin. As of December 31, 2011, approximately 13.4% of our estimated proved reserves were located in the fields that comprise the Illinois Basin and 86.6% of our estimated proved reserves were a result of our Appalachian Basin operations. If mechanical problems, weather conditions or other events were to curtail a substantial portion of the production in one or both of these regions, our cash flow would be adversely affected. If ultimate production associated with these properties is less than our

estimated reserves, or changes in pricing, cost or recovery assumptions in the area results in a downward revision of any estimated reserves in these properties, our business, financial condition and results of operations could be adversely affected.

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil, NGLs and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

We may be required to take additional write-downs of the carrying values of our oil and natural gas properties, potentially triggering earlier-than-anticipated repayments of any outstanding debt obligations and negatively impacting the trading value of our securities.

There is a risk that we will be required to write down the carrying value of our oil and gas properties, which would reduce our earnings and stockholders' equity. We account for our natural gas and crude oil exploration and development activities using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, developmental dry holes and productive wells and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and gas leases are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities. The capitalized costs of our oil and gas properties may not exceed the estimated future net cash flows from our properties. If capitalized costs exceed future cash flows, we write down the costs of the properties to our estimate of fair market value. Any such charge will not affect our cash flow from operating activities, but will reduce our earnings and stockholders' equity.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive but may actually deliver oil and gas in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. The evaluation of oil and gas leasehold acquisition costs requires judgment to estimate the fair value of these costs with reference to drilling activity in a given area.

We review our oil and gas properties for impairment annually or whenever events and circumstances indicate a decline in the recoverability of their carrying value. Once incurred, a write down of oil and gas properties is not reversible at a later date even if gas or oil prices increase. Given the complexities associated with oil and gas reserve estimates and the history of price volatility in the oil and gas markets, events may arise that would require us to record an impairment of the book values associated with oil and gas properties.

For the year ended December 31, 2011, we incurred impairment charges from continuing operations of approximately \$14.6 million. Approximately \$11.6 million of the estimated pre-tax impairment expense for the fourth quarter of 2011 is related to the impairment of shallow conventional natural gas properties in the Appalachian Basin as a result of lower current and projected natural gas prices.

Additional write downs could occur if oil and gas prices decline or if we have substantial downward adjustments to our estimated proved reserves, increases in our estimates of development costs or deterioration in our drilling results. Because our properties currently serve, and will likely continue to serve, as collateral for advances under our existing and future credit facilities, a write-down in the carrying values of our properties could require us to repay debt earlier than we would otherwise be required. It is likely that the cumulative effect of a write-down could also negatively impact the value of our securities, including our common stock.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil, NGL and natural gas operations, and we may not have enough insurance to cover all of the risks that we face.

We maintain insurance coverage against some, but not all, potential losses to protect against the risks we face. We do not carry business interruption insurance. We may elect not to carry insurance if our management believes that the cost of available insurance is excessive relative to the risks presented. In addition, it is not possible to insure fully against pollution and environmental risks.

Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition and results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil, NGLs and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or
 other pollution into the environment, including groundwater and shoreline contamination and soil
 contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapses;
- · fires and explosions;
- · personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us. If a significant accident or other event occurs and is not fully covered by insurance, then that accident or other event could adversely affect our financial condition, results of operations and cash flows.

We are subject to complex laws and regulations that can adversely affect the cost, manner or feasibility of doing business.

The exploration, development, production and sale of oil, NGLs and natural gas are subject to extensive federal, state, and local laws and regulations. Such regulation includes requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells;
- the unitization and pooling of properties;
- the method of drilling and completing wells;

- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the disposal of fluids used or other wastes generated in connection with our drilling operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Under these laws, we could be subject to claims for personal injury or property damages, including natural resource damages, which may result from the impacts of our operations. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws could change in ways that substantially increase our costs of compliance. Any such liabilities, penalties, suspensions, terminations or regulatory changes could have a material adverse effect on our financial condition and results of operations.

We must obtain governmental permits and approvals for our drilling and mid-stream operations, which can be a costly and time consuming process, which may result in delays and restrictions on our operations.

Regulatory authorities exercise considerable discretion in the timing and scope of permit issuance. Requirements imposed by these authorities may be costly and time consuming and may result in delays in the commencement or continuation of our exploration or production operations. For example, we are often required to prepare and present to federal, state or local authorities data pertaining to the effect or impact that proposed exploration for or production of natural gas or oil may have on the environment. Further, the public may comment on and otherwise engage in the permitting process, including through intervention in the courts. Accordingly, the permits we need may not be issued, or if issued, may not be issued in a timely fashion, or may involve requirements that restrict our ability to conduct our operations or to do so profitably.

Our operations expose us to substantial costs and liabilities with respect to environmental matters.

Our oil, NGL and natural gas operations are subject to stringent federal, state and local laws and regulations governing the release of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with our drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas, and impose substantial liabilities for pollution that may result from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory or remedial obligations or the issuance of injunctions restricting or prohibiting certain activities. Under existing environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether the release resulted from our operations, or whether our operations were in compliance with all applicable laws at the time they were performed.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our competitive position, financial condition and results of operations.

Climate change legislation or regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil, natural gas and NGLs that we produce.

In December 2009, the EPA published its findings that emissions of greenhouse gases ("GHGs") present a danger to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the Earth's atmosphere and other climatic conditions. Based on these findings, in

2010 the EPA adopted two sets of regulations that restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one that requires a reduction in emissions of GHGs from motor vehicles and another that requires certain construction and operating permit reviews for GHG emissions from certain large stationary sources. The stationary source final rule addresses the permitting of GHG emissions from stationary sources under the Clean Air Act Prevention of Significant Deterioration, or PSD, construction and Title V operating permit programs, pursuant to which these permit programs have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. In addition, in November 2010, the EPA issued a final rule requiring companies to report certain greenhouse gas emissions from oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. We are evaluating whether GHG emissions from our operations are subject to the GHG emissions reporting rule and expect to be able to comply with any applicable reporting obligations. Also, Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states already have taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs or could adversely affect demand for the oil, natural gas and NGLs we produce. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate change that could have significant physical effect, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if such effects were to occur, they could have an adverse effect on our assets and operations.

The adoption of derivatives legislation by Congress and related regulations could have an adverse impact on our ability to use derivative instruments, particularly swaps, to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Act, was enacted in 2010. The Act provides for new statutory and regulatory requirements for derivative transactions, including certain oil and gas hedging transactions involving swaps. In particular, the Act includes a requirement that certain hedging transactions involving swaps be cleared and exchange-traded and a requirement to post cash collateral for non-cleared swap transactions, although, at this time, it is unclear which transactions will ultimately be required to be cleared and exchange-traded or which counterparties will be required to post cash collateral with respect to non-cleared swap transactions. The Act provides for a potential exception from the clearing and exchange-trading requirement for hedging transactions by commercial end-users, a category of non-financial entities in which we may be included. While the Commodity Futures Trading Commission, or CFTC, and other federal agencies have adopted, and continue to adopt, numerous regulations pursuant to the Act, many of the key concepts and defined terms under the Act have not yet been delineated by rules and regulations to be adopted by the CFTC and other applicable regulatory agencies. As a consequence, it is difficult to predict the aggregate effect the Act and the regulations promulgated thereunder may have on our hedging activities. Whether we are required to submit our swap transactions for clearing or post cash collateral with respect to such transaction will depend on the final rules and definitions adopted by the CFTC. If we are subject to such requirements, significant liquidity issues could result by reducing our ability to use cash posted as collateral for investment or other corporate purposes. A requirement to post cash collateral could also limit our ability to execute strategic hedges, which would result in increased commodity price uncertainty and volatility in our future cash flows. The Act and related regulations will also require us to comply with certain futures and swaps position limits and new recordkeeping and reporting requirements, and may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Act and related regulations could also materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Enactment of a Pennsylvania severance tax and impact fees on natural gas could adversely impact our results of existing operations and the economic viability of exploiting new gas drilling and production opportunities in Pennsylvania.

While Pennsylvania has historically not imposed a severance tax (relating to the extraction of natural gas), with a focus on its budget deficit and the increasing exploration of the Marcellus Shale, various legislation has been proposed since 2008. In February 2012, Pennsylvania implemented an impact fee. This new law imposes an impact fee on all unconventional wells drilled in the Commonwealth of Pennsylvania in counties that elect to impose the fee. The fee, which changes from year to year, is based on the average annual price of natural gas as determined by the NYMEX price, as reported by the Wall Street Journal for the last trading day of each calendar month. Based upon natural gas prices for 2011, operators will pay \$50,000 per unconventional horizontal well. Unconventional vertical wells will pay a fee equal to twenty percent of the horizontal well fee and the impact fee will not apply to any unconventional vertical well that produces less than 90mcf per day. The payment structure for the impact fee makes the fee due the year after an unconventional well is spudded and the fee will continue for 15 years for a horizontal well and 10 years for a vertical well.

Future economic conditions in the U.S. and global markets may have a material adverse impact on our business and financial condition that we currently cannot predict.

The U.S. and other world economies are still recovering from a recession which began in 2008 and extended into 2009. While economic growth has resumed, the timing and extent of an economic recovery are uncertain. There are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than what was experienced in previous years. Unemployment rates remain high and businesses and consumer confidence levels have not yet fully recovered to pre-recession levels. In addition, more volatility may occur before a sustainable, yet lower, growth rate is achieved. Global economic growth drives demand for energy from all sources, including for oil and natural gas. A lower future economic growth rate will result in decreased demand growth for our crude oil, NGL and natural gas production as well as lower commodity prices, which will reduce our cash flows from operations and our profitability.

Our results of operations and cash flow may be adversely affected by risks associated with our oil and gas financial derivative activities, and our oil and gas financial derivative activities may limit potential gains.

We have entered into, and we expect to enter into in the future, oil and gas financial derivative arrangements corresponding to a significant portion of our oil and natural gas production. Many derivative instruments that we employ require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices. We received net payments of \$6.2 million in relation to our commodity derivative instruments for the year ended December 31, 2011.

If our actual production and sales for any period are less than the corresponding volume of derivative contracts for that period (including reductions in production due to operational delays), or if we are unable to perform our activities as planned, we might be forced to satisfy all or a portion of our derivative obligations without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. In addition, our oil and gas financial derivative activities can result in substantial losses. Such losses could occur under various circumstances, including any circumstance in which a counterparty does not perform its obligations under the applicable derivative arrangement, the arrangement is imperfect or our derivative policies and procedures are not followed or do not work as planned. Under the terms of our senior credit facility and second lien credit facility the percentage of our total production volumes with respect to which we will be allowed to enter into derivative contracts is limited, and we therefore retain the risk of a price decrease for our remaining production volume.

We depend on a relatively small number of purchasers for a substantial portion of our revenue. The inability of one or more of our purchasers to meet their obligations or the loss of our market with CountryMark Cooperative, LLP, in particular, may adversely affect our financial results.

We derive a significant amount of our revenue, approximately 96%, from sales to a relatively small number of purchasers. If we were unable to continue to sell our oil, NGLs, or natural gas to these key customers, or to offset any reduction in sales to these customers by additional sales to our other customers, it could adversely affect our financial condition and results of operations. These companies may not provide the same level of our revenue in the future for a variety of reasons, including their lack of funding, a strategic shift on their part in moving to different geographic areas in which we do not operate or our failure to meet their performance criteria. The loss of all or a significant part of this revenue would adversely affect our financial condition and results of operations.

Our business may suffer if we lose key personnel.

Our operations depend on the continuing efforts of our executive officers and senior management. Our business or prospects could be adversely affected if any of these persons does not continue in their management role with us and we are unable to attract and retain qualified replacements. Additionally, we do not carry key person insurance for any of our executive officers or senior management.

Our future acquisitions may yield revenue or production that varies significantly from our projections.

In pursuing potential acquisition of oil and natural gas properties, we will assess the potential recoverable reserves, future natural gas and oil prices, operating costs, potential liabilities and other factors relating to the properties. Our assessments are necessarily inexact, and their accuracy is inherently uncertain. Our review of a subject property in connection with our acquisition assessment will not reveal all existing or potential problems or permit us to become sufficiently familiar with the property to assess fully its deficiencies and capabilities. We may not inspect every well, and we may not be able to observe structural and environmental problems even when we do inspect a well. If problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of those problems. Any acquisition of property interests may not be economically successful, and unsuccessful acquisitions may have a material adverse effect on our financial condition and future results of operations.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

Congress has recently considered, is considering, and may continue to consider, legislation that, if adopted in its proposed or similar form, would deprive some companies involved in oil and natural gas exploration and production activities of certain U.S. federal income tax incentives and deductions currently available to such companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective and whether such changes may apply retroactively. Although we are unable to predict whether any of these or other proposals will ultimately be enacted, the passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or postpone certain tax deductions that are currently available to us, and any such change could negatively affect our financial condition and results of operations.

New technologies may cause our current exploration and drilling methods to become obsolete.

The oil and gas industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. One or more of the technologies that we currently use or that we may implement in the future may become obsolete. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. If we are unable to maintain technological advancements consistent with industry standards, our operations and financial condition may be adversely affected.

The outcome of litigation in which we have been named as a defendant is unpredictable and an adverse decision in any such matter could have a material adverse effect on our financial position or results of operations.

We are defendants in a number of litigation matters and are subject to various other claims, demands and investigations. These matters may divert financial and management resources that would otherwise be used to benefit our operations. No assurances can be given that the results of these matters will be favorable to us. An adverse resolution or outcome of any of these lawsuits, claims, demands or investigations could have a negative impact on our financial condition, results of operations and liquidity.

Risks Related to Our Common Stock

We may issue additional common stock in the future, which would dilute our existing stockholders.

In the future we may issue our previously authorized and unissued securities, including shares of our common stock or securities convertible into or exchangeable for our common stock, resulting in the dilution of the ownership interests of our stockholders. We are authorized under our amended and restated certificate of incorporation to issue 100,000,000 shares of common stock and 100,000 shares of preferred stock with such designations, preferences, and rights as may be determined by our board of directors. As of March 9, 2012, there were 52,902,996 shares of our common stock issued and outstanding and there were no shares of our preferred stock issued and outstanding.

We have an effective shelf registration statement from which additional shares of our common stock and other securities can be issued. We may also issue additional shares of our common stock or securities convertible into or exchangeable for our common stock in connection with future public offerings, the hiring of personnel, future acquisitions, future private placements of our securities for capital raising purposes or for other business purposes. Future issuances of our common stock, or the perception that such issuances could occur, could have a material adverse effect on the price of our common stock.

Our amended and restated certificate of incorporation, amended and restated bylaws, and Delaware law contain provisions that could make it more difficult for a third party to acquire us without the consent of our board of directors and our Chairman and other executive officers, who collectively beneficially own approximately 21% of the outstanding shares of our common stock as of March 9, 2012.

Provisions in our amended and restated certificate of incorporation and amended and restated bylaws could have the effect of delaying or preventing a change of control of us and changes in our management. These provisions include the following:

• the ability of our board of directors to issue shares of our common stock and preferred stock without stockholder approval;

- the ability of our board of directors to make, alter, or repeal our bylaws without further stockholder approva
- the requirement for advance notice of director nominations to our board of directors and for proposing other matters to be acted upon at stockholder meetings;
- requiring that special meetings of stockholders be called only by our Chairman, by a majority of our board of directors, by our Chief Executive Officer or by our President; and
- allowing our directors, and not our stockholders, to fill vacancies on the board of directors, including vacancies resulting from removal or enlargement of the board of directors.

In addition, we are subject to the provisions of Section 203 of the Delaware General Corporation Law. These provisions may prohibit large stockholders, in particular those owning 15% or more of our outstanding voting stock, from merging or combining with us.

As of March 9, 2012, our board of directors, including Lance T. Shaner, our Chairman, and our other executive officers collectively own approximately 21% of the outstanding shares of our common stock. Although this is not a majority of our outstanding common stock, these stockholders, acting together, will have the ability to exert substantial influence over all matters requiring stockholder approval, including the election and removal of directors, any proposed merger, consolidation, or sale of all or substantially all of our assets and other corporate transactions.

The provisions in our amended and restated certificate of incorporation and amended and restated bylaws and under Delaware law, and the concentrated ownership of our common stock by our Chairman and other executive officers, could discourage potential takeover attempts and could reduce the price that investors might be willing to pay for shares of our common stock.

Because we have no plans to pay dividends on our common stock, stockholders must look solely to appreciation of our common stock to realize a gain on their investments.

We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, our senior credit facility and our second lien credit facility limits the payment of dividends without the prior written consent of the lenders. Accordingly, stockholders must look solely to appreciation of our common stock to realize a gain on their investment. This appreciation may not occur.

We are able to issue shares of preferred stock with greater rights than our common stock.

Our amended and restated certificate of incorporation authorizes our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from our stockholders. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, liquidation rights, or voting rights. If we issue preferred stock, it may adversely affect the market price of our common stock.

Substantial sales of our common stock could cause our stock price to decline.

If our stockholders sell a substantial number of shares of our common stock, or the public market perceives that our stockholders might sell shares of our common stock, the market price of our common stock could decline significantly. We cannot predict the effect that future sales of our common stock or other equity-related securities by our stockholders would have on the market price of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

As of the date of this filing, we have no unresolved comments from the staff of the SEC.

ITEM 2. PROPERTIES

The table below summarizes certain data for our core operating areas for the year ended December 31, 2011:

Division	Average Daily Production (Mcfe per day)	Total Production (Mcfe)	Percentage of Total Production	Total Estimated Proved Reserves (Mcfe)	Percentage of Total Estimated Proved Reserves
Illinois Basin	11,398	4,160,454	29.3%	49,087,200	13.4%
Appalachian Basin	27,560	10,059,414	70.7%	317,101,100	86.6%
Totals	38,958	14,219,868	100.0%	366,188,300	100.0%

Segment reporting is not applicable to us, as we have a single company-wide management team that administers all properties as a whole rather than by discrete operating segments. We track only basic operational data by area. We do not maintain complete separate financial statement information by area. We measure financial performance as a single enterprise and not on an area-by-area basis.

Illinois Basin

In the Illinois Basin, we own an interest in 1,842 wells, which includes 506 disposal and injection wells. We have approximately 61,700 gross (35,000 net) acres owned and under lease.

Total estimated proved reserves, and proved developed reserves, in the Illinois Basin increased approximately 0.2 Bcfe, or 0.5%, to approximately 49.1 Bcfe at December 31, 2011 when compared to year-end 2010, which was primarily a result of the addition of estimated proved reserves from our ASP project and increased oil prices, partially offset by natural production declines. Annual production increased 0.3% from 2010. Capital expenditures in 2011 for drilling and facility improvements in the region were approximately \$13.3 million, which funded the drilling of six gross (three net) wells, of which four gross (two net) was awaiting completion as of December 31, 2011. These expenditures also covered work performed in the basin designed to optimize our secondary waterflood operations whereby we stabilized declining production. Capital expenditures for drilling and facilities development for the Lawrence Field ASP Flood Project totaled approximately \$4.0 million.

Lawrence Field ASP Flood Project

We are implementing an alkali-surfactant-polymer ("ASP") flood project in the Cypress and Bridgeport Sandstone reservoirs of our Lawrence Field acreage. The Lawrence Field ASP Flood Project is considered an Enhanced Oil Recovery ("EOR") project, which refers to recovery of oil that is not producible by primary or secondary recovery methods.

We currently own and operate 21.2 square miles (approximately 13,500 net acres) of the Lawrence Field. The Cypress (Mississippian) and the Bridgeport (Pennsylvanian) sandstones are the major producing horizons in the field. To date, approximately 40% of the estimated one billion barrels of original oil in place has been produced.

In the 1960s, 1970s and 1980s, a number of EOR projects using surfactant polymer floods were implemented in several fields in the Illinois Basin by Marathon Oil Corp. ("Marathon"), Texaco and Exxon in an

attempt to recover a portion of the large percentage of the original oil in place that was being bypassed by the secondary recovery waterflood. These test projects reportedly were able to recover incremental oil reserves of 15% to 30% of the original oil in place. While we believe the results of these projects are pertinent, there can be no assurance that our Lawrence Field ASP Flood Project, which uses technology that was not developed at the time of the prior EOR projects, will achieve similar results. ASP technology, which uses mechanisms to mobilize bypassed residual oil similar to these previous surfactant polymer floods but at significantly lower costs, has been applied by other companies in several fields around the world resulting in significant incremental recoveries of the original oil in place. Chemicals used in the Lawrence Field ASP Flood Project are an alkali, a surfactant and a polymer. The alkali and surfactant combination acts like a soap and washes residual oil from the reservoir mainly by reducing interfacial tension between the oil and the water. The polymer is added to improve sweep displacement efficiency by pushing the "washed" oil through the rock pores of the reservoir.

The goal of our Lawrence Field ASP Flood Project is to duplicate the oil recovery performance of the surfactant polymer floods conducted in the field in the 1980s, but at a significantly lower cost. We expect this cost reduction to be accomplished by utilizing newer technologies to optimize the synergistic performance of the three chemicals used, and by using alkali in the formula, which would allow us to use a significantly lower concentration of the more costly surfactant.

In 2000, PennTex Resources Illinois, Inc., one of our Predecessor Companies, then known as Plains Illinois, Inc., and the U.S. Department of Energy conducted a study on the potential of an ASP project in the Lawrence Field, with consulting services provided by an independent engineering firm specializing in the design and implementation of chemical oil recovery systems. Based on the modeling of the reservoir characteristics and laboratory tests with cores taken in the Lawrence Field, the evaluation found oil recovery in the field could be increased significantly by installing an ASP flood. However, there can be no assurance that our Lawrence Field ASP Flood Project will achieve similar results to those conducted in the study.

During 2008 and 2009, we completed two four acre pilot tests, one each in the Bridgeport and Cypress sandstones. Both of the pilots demonstrated a response to the chemical injection, as indicated by an increase in both oil production and the oil cut ratio. Each pilot area had individual wells whose oil cut exceeded 10% after the initial response; whereas the oil cuts for both pilots at the time ASP injection was initiated were less than 1%. During 2010 we commenced chemical injection into our 15-acre Middagh ASP pilot unit and received initial and peak response during 2011, with oil cuts increasing from 1% to approximately 12%, with several wells peaking at an oil cut of 17%. Production has since began its gradual decline, however the successful response from this project resulted in the assignment of 107.6 MBbls of net proved developed non-producing reserves as of December 31, 2011. We are continuing to move forward with ASP expansion with the 58-acre Perkins Smith project area. ASP injection into the Perkins Smith is expected to begin in the second quarter of 2012, with initial production response expected early in 2013. Development and testing work is underway to initiate the potentially high impact 351-acre Delta Unit ASP flood. We are currently evaluating various development and spacing scenarios to determine the optimal pattern performance in this project.

We have identified, thus far, 27 potential separate flood units (15 Bridgeport/12 Cypress). Depending on the size of each flood unit, it is anticipated that initial response time from the chemical injection date will be approximately 10 to 12 months and the time to peak response will be approximately 24 to 30 months.

Appalachian Basin

As of December 31, 2011, we owned an interest in approximately 512 producing natural gas wells in the Appalachian Basin, located predominantly in Pennsylvania. In addition to our producing wells in the basin, we own 89.0 gross Marcellus Shale PUD drilling locations and 1.0 gross Burkett Shale PUD drilling location with total reserves of 192.9 Bcfe, and three locations,

including one each in the Marcellus, Utica, and Burkett Shale plays, with proved developed non-producing reserves totaling 8.3 Bcfe. At December 31, 2011, we had approximately 162,200 gross (93,900 net) acres in the Appalachian Basin under lease, of which 104,100 gross (69,400 net) acres were undeveloped.

Reserves at December 31, 2011 increased 164.3 Bcfe, or 107.5%, from 2010 due primarily to our successful Marcellus Shale exploration activities. Annual production increased 210.2% over 2010.

Capital expenditures in 2011 for drilling and facility development totaled \$187.3 million, which funded the drilling of 57.0 gross (30.2 net) wells. During the year, we placed into service 51.0 gross (25.9 gross) wells and had an inventory of 25.0 gross (15.2 net) wells awaiting completion or a pipeline connection. Our plans for 2012 have allocated approximately \$133.7 million in capital expenditures to our Marcellus, Utica and Burkett Shale project areas.

Marcellus Shale

As of December 31, 2011, we had interests in approximately 129,200 gross (66,400 net) Marcellus Shale prospective acres in areas of Pennsylvania and we continue to expand our position by strategically filling in key pieces of acreage to complete drilling units.

In June of 2009, we entered into a Participation and Exploration Agreement (the "Williams PEA") with WPX Energy San Juan, LLC (formerly known as Williams Production Company, LLC) and Williams Production Appalachia, LLC, whom we collectively refer to as "Williams". Under the terms and conditions of the Williams PEA, Williams acquired, through a "drill-to-earn" structure, 50% of our working interest in certain oil and gas leases covering approximately 44,000 net acres in Centre, Clearfield and Westmoreland Counties, Pennsylvania (the "Project Area"). The Williams PEA effectively provided that, for Williams to earn its 50% interest in the Project Area, Williams had to bear 90% of all costs and expenses incurred in the drilling and completion of all wells jointly drilled in the Project Area until such time as Williams had invested approximately \$74.0 million (approximately \$33.0 million on behalf of us and \$41.0 million for Williams' 50% share of the wells). Once Williams completed its carry obligation and acquired 50% of our working interest in the leases within the Project Area, the parties would become obligated to share all costs of the joint venture operations with an area of mutual interest (including the Project Area) in accordance with their participating interests, which were expected to be on a 50/50 basis prior to our Sumitomo joint venture transaction (described below). Williams met its drilling carry obligation during the fourth quarter of 2010.

On September 30, 2010, we entered into a joint venture transaction with Summit Discovery Resources II, LLC and Sumitomo Corporation, whom we collectively refer to herein as "Sumitomo". In Butler, Beaver and Lawrence Counties, Pennsylvania we sold a 15% non-operated interest in approximately 41,000 net acres for approximately \$30.6 million in cash at closing and \$30.6 million in the form of a drilling carry of 80% of our drilling and completion costs in the area. Pursuant to the Participation and Exploration Agreement (the "Sumitomo PEA"), Sumitomo agreed to pay all costs to lease approximately 9,000 acres in the Butler County Area of Mutual Interest ("AMI") (the "Phase I Leasing"), and was obligated to pay to us a leasing management fee of \$1,000 per net acre during the Phase I Leasing. Under the Sumitomo PEA, upon the conclusion of Phase I Leasing, we were required to cross assign interests in the leases with Sumitomo to provide uniformity of interest in each lease in the Butler County AMI. The Phase I Leasing Project is substantially complete, with the final ownership percentages in the Butler County AMI being approximately 70% to us and 30% to Sumitomo. In addition to the sale of undeveloped acreage, we also sold to Sumitomo 30% of our interests in 20 Marcellus Shale wells within the Butler County AMI and 30% of our interest in Keystone Midstream Services, LLC.

In our Marcellus Shale joint venture Project Area with Williams, which is discussed above, we sold to Sumitomo 20% of our interests in 21,000 net acres for approximately \$19.0 million in cash at closing and \$19.0 million in the form of a drilling carry of 80% of our drilling and completion costs in the Project Area. In addition,

we sold 20% of our interests in 19 Marcellus Shale wells located in the Williams joint venture areas and 20% of our interest in RW Gathering, LLC. The resulting working interest ownership is 50% Williams, 40% Rex Energy and 10% Sumitomo.

In addition to the areas above, we sold to Sumitomo 50% of our interests in approximately 4,500 net acres in Fayette and Centre Counties, Pennsylvania for \$9.2 million in cash at closing and \$9.2 million in the form of a drilling carry of 80% of our drilling and completion costs. Pursuant to the Sumitomo PEA, the drilling carry for these areas was able to be applied, at our discretion, to drilling and completion costs attributable to either the Butler County or Williams Project Areas.

At closing, we received approximately \$99.5 million in cash, which included a reimbursement for leasing expenses incurred subsequent to the effective date of September 1, 2010, in the amount of \$7.6 million. Additionally, the cash payment included a reimbursement for drilling related expenses incurred subsequent to the effective date in the amount of approximately \$7.5 million, which was applied against the drilling carry. Sumitomo met its drilling carry obligation during the first quarter of 2011.

Utica Shale

During 2011, we drilled our first Utica Shale test well for which we successfully booked proved developed non-producing reserves, as the well was awaiting pipeline construction at the end of the year. We estimate that much of our acreage in Butler County, Pennsylvania is prospective for dry gas Utica Shale production as well as acreage in some other non-core areas of Pennsylvania. As of December 31, 2011, we estimate Utica Shale acreage holdings in Pennsylvania of approximately 92,300 gross (56,400 net).

We expanded our Utica Shale exploration activities into Ohio during 2011, acquiring approximately 13,000 gross (12,900 net) acres, not including 2,000 gross (2,000 net) acres that are pending the clearance of title, which we believe to be prospective for liquids-rich production. We plan to spud the first test well in Ohio during the second quarter of 2012.

Burkett Shale

During 2011, we drilled our first Burkett Shale test well for which we successfully booked proved developed non-producing reserves, as the well was awaiting pipeline connection at the end of the year. The Burkett Shale is one of the shales that lies within the Upper Devonian formation. We estimate that much of our acreage in Butler County, Pennsylvania is prospective for wet gas Burkett Shale production. As of December 31, 2011, we estimate Burkett Shale acreage holdings of approximately 67,200 gross (44,800 net).

Estimated Proved Reserves

For estimated proved reserves as of December 31, 2011, proved locations were identified, assessed and justified using the evaluation methods of performance analysis, volumetric analysis and analogy. In addition, reliable technologies were used to support a select number of undeveloped locations in the Marcellus Shale Region. Within the Marcellus Shale Region, we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This data included performance data, seismic data, micro-seismic analysis, open hole log information and petro-physical analysis of the log data, mud logs, log cross-sections, gas sample analysis, drill cutting samples, measurements of total organic content, thermal maturity and statistical analysis. In our development area, these data demonstrated consistent and continuous reservoir characteristics.

The following table sets forth our estimated proved reserves as defined in Rule 4.10(a) of Regulation S-X and Item 1200 of Regulation S-K:

Category	Oil (Barrels)	NGL (Barrels)	Gas (Mcf)
Proved Developed	8,073,600	2,024,660	103,707,500
Proved Developed Non-Producing	107,600	193,760	7,145,800
Proved Undeveloped		4,916,380	163,439,000
Total Proved	8,181,200	7,134,800	274,292,300

All of our reserves are located within the continental United States. Reserve estimates are inherently imprecise and remain subject to revisions based on production history, results of additional exploration and development, prices of oil and natural gas and other factors. Please read "Item 1A—Risk Factors—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves." You should also read the notes following the table below and our Consolidated Financial Statements for the year ended December 31, 2011 in conjunction with the following reserve estimates.

The following table sets forth our estimated proved reserves at the end of each of the past three years:

	2011	2010	2009
Description			
Proved Developed Reserves			
Oil (Bbls)	8,181,200	8,142,779	8,526,279
Natural Gas (Mcf)	110,853,300	32,477,226	16,161,494
NGLs (Bbls)	2,218,420	656,326	97,151
Proved Undeveloped Reserves			
Oil (Bbls)		-	1,751,178
Natural Gas (Mcf)	163,439,000	95,144,609	40,001,676
NGLs (Bbls)	4,916,380	3,543,723	1,135,375
Total Estimated Proved Reserves (Mcfe) ^{1, 2, 3}	366,188,300	201,678,803	125,223,068
PV-10 Value (millions) ^{2,4}	\$ 539.6	\$ 269.4	\$ 190.5
Standardized Measure (millions) ²	\$ 413.9	\$ 188.1	\$ 144.4

The estimates of reserves in the table above conform to the guidelines of the SEC. Estimated recoverable proved reserves have been determined without regard to any economic impact that may result from our financial derivative activities. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The reserve information shown is estimated. The certainty of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and geological interpretation and judgment. The estimates of reserves, future cash flows and present value are based on various assumptions, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates.

Totals of estimated proved reserves, PV-10 Value and Standardized Measure exclude values from our DJ Basin properties which are classified as Held for Sale on our Consolidated Balance Sheet at December 31, 2010 and 2011.

We converted crude oil and NGLs to Mcf equivalent at a ratio of one barrel to six Mcfe.

Represents the present value, discounted at 10% annum (PV-10), of estimated future cash flows of our estimated proved reserves before income tax and asset retirement obligations. The estimated future cash flows set forth above were determined by using reserve quantities of estimated proved reserves and the

periods in which they are expected to be developed and produced based on prevailing economic conditions. The estimated future production is priced based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December 2011, using \$92.45 per barrel of oil, \$46.34 per barrel of NGLs and \$4.545 per Mcf of natural gas, adjusted by lease for transportation fees and regional price differentials. Management believes that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. For an explanation of why we show PV-10 and a reconciliation of PV-10 to the standardized measure of discounted future net cash flow, please read "Item 6. Selected Historical Financial and Operating Data—Non-GAAP Financial Measures." Please also read "Item 1A. Risk Factors—Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions may materially affect the quantities and present value of our reserves."

Proved Undeveloped Reserves (PUDs)

As of December 31, 2011, our PUD reserves totaled 4.9 MMBOE of NGLs and 163.4 Bcf of natural gas, for a total of 192.9 Bcfe. All of our PUDs at year-end 2011 were associated with the Appalachian Basin. All of these projects will have PUDs convert from undeveloped to developed as these projects begin production and/or production facilities are expanded or upgraded. Changes in PUDs that occurred during the year were due to:

- conversion of approximately 31.1 Bcfe attributable to PUDs into proved developed reserves;
- 102.9 Bcfe in PUDs due to extensions and discoveries, which are primarily related to the extension of proved acreage in areas that are prospective for the Marcellus and Upper Devonian (Burkett) Shale, through our drilling activities. During 2011, we drilled approximately 44.0 gross (23.6 net) Marcellus Shale wells that were not considered proved in addition to 13.0 gross (6.6 net) Marcellus Shale wells that were classified as PUDs as of December 31, 2010.

Costs incurred relating to the development of 16.0 gross (9.5 net) PUDs to proved developed were approximately \$20.2 million in 2011. Estimated future development costs relating to the development of our 90.0 gross (54.1 net) PUDs are projected to be approximately \$44.9 million in 2012, \$52.1 million in 2013, \$104.7 million in 2014 and \$46.1 million in 2015.

All PUD drilling locations are scheduled to be drilled prior to the end of 2015, including approximately 13.3% of the total in 2012. Initial production from these PUDs is expected to begin between 2012 and 2016. We do not have PUDs associated with reserves that have been booked for longer than five years. Approximately 33.0 gross (18.6 net) PUDs were booked based on reliable technology.

The following table summarizes the changes in our proved undeveloped reserves for the year ended December 31, 2011:

Proved Undeveloped Reserves (Mcfe)	For the Year Ended December 31, 2011
Beginning proved undeveloped reserves	116,406,947
Undeveloped reserves converted to developed	(31,134,599)
Revisions	4,812,084
Extensions and discoveries	102,853,215
Ending proved undeveloped reserves	192,937,647

Reserve Estimation

Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm, evaluated our reserves on a consolidated basis as of December 31, 2011. At December 31, 2011, these consultants collectively

reviewed all of our estimated proved reserves. A copy of the summary reserve report is included as Exhibit 99.1 to this Annual Report on Form 10-K. The technical persons responsible for preparing our estimated proved reserves estimates meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with NSAI to ensure the integrity, accuracy and timeliness of the data used to calculate our estimated proved reserves. Our internal technical team members meet with NSAI periodically throughout the year to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to NSAI for our properties such as ownership interest; oil and gas production; well test data; commodity prices and operating and development costs. The preparation of our proved reserve estimates are completed in accordance with our internal control procedures, which include documented process workflows, the verification of input data used by NSAI, as well as extensive management review and approval.

All of our reserve estimates are reviewed and approved by our Director, Reservoir Engineering and our President and Chief Operating Officer. Our Director, Reservoir Engineering holds a Bachelor of Science degree in Petroleum Engineering from the University of Texas at Austin with more than seven years of experience in preparing reserve reports under the guidelines of the SEC with Cano Petroleum and with us. Our President and Chief Operating Officer holds a Bachelor of Science degree in Petroleum Engineering from the University of Wyoming and an M.B.A. from Pepperdine University, with approximately 25 years of experience working for companies such as Cano Petroleum, Pioneer Natural Resources and Union Pacific Resources.

Acreage and Productive Wells Summary

The following table sets forth, for our continuing operations, our gross and net acreage of developed and undeveloped oil and natural gas leases and our gross and net productive oil and natural gas wells as of December 31, 2011:

	Undeve Acres		Develo Acrea		To Acre		Producii Wel		Produc We	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin										
Pennsylvania	91,000	56,500	58,100	24,500	149,100	81,000	512	231		_
Ohio	13,000	12,900			13,000	12,900				
Total										
Appalachian										
Basin	104,000	69,400	58,100	24,500	162,100	93,900	512	231		
Illinois Basin										
Illinois	400	200	48,600	24,800	49,000	25,000			1,140	1,131
Indiana		_	10,800	9,500	10,800	9,500			196	191
Kentucky			2,100	500	2,100	500				
Total Illinois										
Basin	400	200	61,500	34,800	61,900	35,000		_	1,336	1,322
Total	104,400	69,600	119,600	59,300	224,000	128,900	512	231	1,336	1,322

⁽¹⁾ Undeveloped acreage is lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage includes estimated proved reserves.

⁽²⁾ Developed acreage is the number of acres allocated or assignable to producing wells or wells capable of production.

Substantially all of the undeveloped leases summarized in the preceding table will expire at the end of their respective primary terms unless the existing lease is renewed, we have commenced the necessary operations required by the terms of the lease, or have obtained actual production from acreage subject to the lease, in which event, the lease will remain in effect until the cessation of production.

The following table sets forth, for our continuing operations, the gross and net acres of undeveloped land subject to leases summarized in the preceding table that will expire during the periods indicated:

	Expiring	Acreage
	Gross	Net
Year Ending December 31,		
2012	16,223	11,057
2013	24,986	11,173
2014	17,486	11,308
2015	29,698	16,329
Thereafter	28,076	25,520
Total	116,469	75,387

Drilling Results

The following table summarizes our drilling activity for continuing operations for the past three years. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. All of our drilling activities are conducted on a contract basis by independent drilling contractors. We own four workover rigs, which are used in our Illinois Basin operations. We do not own any drilling equipment.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Illinois Basin ¹	6.0	3.0	14.0	10.9	23.0	23.0
Appalachian Basin	13.0	6.6	14.0	8.0	1.0	1.0
DJ Basin ²					_	
Non-Productive			1.0	1.0		
Total Developmental Wells	19.0	9.6	29.0	19.9	24.0	24.0
Exploratory:						
Illinois Basin	_	—				
Appalachian Basin	44.0	23.6	13.0	7.0	6.0	3.0
DJ Basin ²	1.0	1.0	2.0	1.5		
Non-Productive	1.0	1.0			1.0	1.0
Total Exploratory Wells	46.0	25.6	17.0	10.5	7.0	4.0
Total Wells	65.0	35.2	46.0	30.4	31.0	28.0
Success Ratio ³	97.4%	94.8%	87.5%	81.9%	96.8%	96.4%

Does not include wells drilled for our ASP project.

DJ Basin assets are classified as held for sale as of December 31, 2011.

Success ratio is calculated by dividing the total successful wells drilled, less any wells awaiting completion as of December 31, divided by the total wells drilled, less any wells awaiting completion as of December 31. As of December 31, 2011, 2010 and 2009 we had 27.0 gross (16.1 net) wells, 21.0 gross (13.1 net) wells and seven gross (6.5 net) wells, respectively, awaiting completion. These wells relate to active projects in the Appalachian Basin and Illinois Basin and are expected to be completed and producing in 2012.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often minimal investigation of record title is made at the time of lease acquisition. A more comprehensive mineral title opinion review, a topographic evaluation and infrastructure investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

- · customary royalty interests;
- liens incident to operating agreements and for current taxes;
- obligations or duties under applicable laws;
- · development obligations under oil and gas leases;
- · net profit interests;
- · overriding royalty interests;
- non-surface occupancy leases; and
- lessor consents to placement of wells.

ITEM 3. LEGAL PROCEEDINGS

The information set forth in Note 24, *Litigation*, in the notes to our Consolidated Financial Statements included in Item 8 of Part II of this report is incorporated herein by reference.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

We completed the initial public offering of our common stock in July 2007. Since that time, our common stock has been quoted on the NASDAQ Global Market under the symbol "REXX". Before then, there was no public market for our common stock. As of March 9, 2012, there were approximately 88 holders of record of our common stock.

The following table sets forth, for the periods indicated, the range of the daily high and low sale prices for our common stock as reported by NASDAQ.

2011	High	Low
First Quarter	\$14.33	\$10.31
Second Quarter	13.18	9.67
Third Quarter	15.64	9.96
Fourth Quarter	18.00	10.63
2010	High	Low
2010 First Quarter	High \$15.39	Low \$10.77
First Quarter	\$15.39	\$10.77

The closing price of our common stock on March 9, 2012 was \$10.71.

Dividends

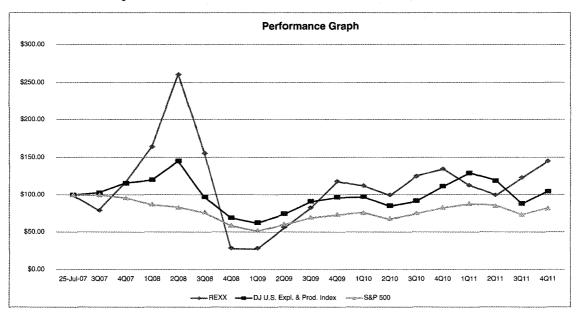
We have not paid cash dividends on our common stock since our inception in March 2007. We do not anticipate paying any dividends on the shares of our common stock in the foreseeable future. We currently intend to reinvest our earnings to finance the expansion of our business. In addition, the terms of our senior credit facility generally prohibit the payment of cash dividends to holders of our common stock.

Issuer Purchases of Equity Securities

We do not have a stock repurchase program for our common stock.

Performance Graph

The following graph presents a comparison of the yearly percentage change in the cumulative total return on our common stock over the period from July 25, 2007, the date our common stock was first publicly traded, to December 31, 2011, with the cumulative total return of the S&P 500 index and the Dow Jones U.S. Oil and Gas Exploration and Production Index over the same period. The graph assumes that \$100 was invested on July 25, 2007 in our common stock at the closing market price at the beginning of this period and in each of the other two indices, and the reinvestment of all dividends, if any. This historic stock price performance is not necessarily indicative of future stock performance.



	S&P	DJ U.S. E&P Index	Rex Energy
July 25, 2007	\$100	\$100	\$100
December 31, 2007	\$ 97	\$117	\$118
December 31, 2008	\$ 60	\$ 69	\$ 29
December 31, 2009	\$ 73	\$ 97	\$118
December 31, 2010	\$ 83	\$112	\$135
December 31, 2011	\$ 83	\$106	\$146

^{*} The performance graph and the information contained in this section is not "soliciting material," is being "furnished," not "filed" with the SEC and is not to be incorporated by reference into any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof, and irrespective of any general incorporation language contained in such filing.

ITEM 6. SELECTED FINANCIAL DATA

Summary Financial Data

The following table shows selected consolidated and combined financial data of Rex Energy Corporation and the Predecessor Companies for each of the periods indicated. The historical consolidated financial data has been prepared for Rex Energy Corporation for the years ended December 31, 2011, 2010, 2009 and 2008. The historical combined financial data has been prepared for the Predecessor Companies for the year ended December 31, 2007. The historical consolidated and combined financial statements for all years presented are derived from the historical audited financial data of Rex Energy Corporation and the Predecessor Companies. All material intercompany balances and transactions have been eliminated. Because each of the Predecessor Companies was taxed as a partnership for each of the periods indicated for federal and state income tax purposes, the following statements make no provision for income taxes for the seven month period ended July 31, 2007. Provision for income tax is presented for the five month period ended December 31, 2007. This information should be read in conjunction with Item 7 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and our Consolidated Financial Statements and related notes as of December 31, 2011 and 2010 and for each of the years ended December 31, 2011, 2010 and 2009, included elsewhere in this report. These selected combined historical financial results may not be indicative of our future financial or operating results.

The following tables include the non-GAAP financial measure of EBITDAX. For a definition of EBITDAX and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Non-GAAP Financial Measures" section.

preuse see Tron Griff Financial Measures section.					Rex Energy
	Rex Energy Corporation Consolidated	Rex Energy Corporation Consolidated	Rex Energy Corporation Consolidated	Rex Energy Corporation Consolidated	Corporation Consolidated & Combined Predecessor Companies
			Ended December ands, Except per		
	2011	2010	2009	2008	2007
Statement of Operations Data: Operating Revenue:	£111.070	Φ. (7.004	Φ 40.524	Φ. 04.012	Ф.50.122
Oil, Natural Gas and NGL Sales Other Revenue	\$111,879 2,727	\$ 67,224 1,539	\$ 48,534 157	\$ 84,013 123	\$ 58,133 101
Total Operating Revenue Operating Expenses:	114,606	68,763	48,691	84,136	58,234
Production and Lease Operating Expense	33,116	24,656	22,157	26,511	22,361
General and Administrative Expense	23,636 502	17,141 (16,395)	15,858 427	15,185 6,468	7,793 (12)
Impairment Expense	14,631	8,863	1,625	71,349	(12)
Exploration Expense	2,507	2,578	2,080	3,261	1,238
Depreciation, Depletion, Amortization &	_,,-	_,	_,	-,	-,
Accretion	28,361 2,569	21,806 1,341	25,205 —	37,904 —	17,804 —
Total Operating Expenses	105,322	59,990	67,352	160,678	49,184
Income (Loss) from Operations Other Income (Expense):	9,284	8,773	(18,661)	(76,542)	9,050
Interest Income	10	68	7	328	15
Interest Expense	(2,019)	(1,070)	(833)	(1,091)	(5,665)
Gain (Loss) on Derivatives, Net	18,916	6,055	(7,913)	27,328	(32,429)
Other Income (Expense)	79 81	(321) (200)	(161)	(114) (54)	(6) (12)
			(9)		(12)
Total Other Income (Expense)	17,067	4,532	(8,909)	26,397	(38,097)
Income Tax Income Tax Benefit (Expense)	26,351 (8,270)	13,305 (5,500)	(27,570) 11,002	(50,145) 9,167	(29,047) 7,365
Income (Loss) from Continuing Operations	18,081	7,805	(16,568)	(40,978)	(21,682)
Income Taxes	(33,457)	(2,022)	323	(7,704)	(681)
Net Income (Loss)	(15,376)	5,783	(16,245)	(48,682)	(22,363)
Interests	(7)	(253)	(12)		6,152
Net Income (Loss) Attributable to Rex Energy	\$(15,369)	\$ 6,036	\$(16,233) =====	\$ (48,682) =====	\$(16,211)
Earnings per Common Share ¹					
Basic—income (loss) from continuing operations attributable to Rex common shareholders	\$ 0.41	\$ 0.18	\$ (0.45)	\$ (1.18)	\$ (0.73)
attributable to Rex common shareholders	(0.76)	(0.05)	0.01	(0.22)	(0.02)
Basic—net income (loss) attributable to Rex common shareholders	\$ (0.35)	\$ 0.13	\$ (0.44)	\$ (1.40)	\$ (0.75)
Basic— weighted average shares of common stock outstanding	43,930	43,281	36,806	34,595	30,795
Diluted—income (loss) from continuing operations attributable to Rex common shareholders	\$ 0.41	\$ 0.18	\$ (0.45)	\$ (1.18)	\$ (0.73)
Diluted— income (loss) from discontinued operations attributable to Rex common shareholders	(0.76)	(0.05)	0.01	(0.22)	(0.02)
Diluted—net income (loss) attributable to Rex common shareholders	\$ (0.35)	\$ 0.13	\$ (0.44)	\$ (1.40)	\$ (0.75)
Diluted—weighted average shares of common stock					=====
outstanding	44,476	43,670	36,806	34,595	30,795

Earnings per common share for 2007 represents a loss from continuing operations of \$11,304 and a gain from discontinued operations of \$664 for the 5 month period ended December 31, 2007.

Year Ended December 31, (\$ in Thousands)

	(\$ in Thousands)							
	2011	2010	2009	2008	2007			
Other Financial Data:								
EBITDAX from Continuing Operations	\$ 64,524	\$ 26,985	\$ 22,495	\$ 29,119	\$ 28,225			
Cash Flow Data:								
Cash provided by operating activities	64,507	18,016	20,774	32,428	17,555			
Cash used by investing activities	(276,574)	(78,835)	(30,061)	(127,800)	(40,102)			
Cash provided by financing activities	212,855	66,245	7,823	101,333	23,032			
Balance Sheet Data:								
Cash and Cash Equivalents	11,796	11,008	5,582	7,046	1,085			
Property and Equipment (net of Accumulated								
Depreciation)	480,244	275,923	275,261	249,858	191,171			
Total Assets	601,551	407,085	304,950	302,006	268,264			
Current Liabilities, including current portion of								
Long-Term Debt	63,366	63,337	32,411	17,353	20,612			
Long-Term Debt, net of current maturities	225,138	10,120	23,049	15,000	27,207			
Total Liabilities	309,277	102,409	84,753	70,158	103,827			
Noncontrolling Interests	275	295	3,343					
Owners' Equity	292,274	304,676	220,197	231,848	164,437			

Summary Operating and Reserve Data

The following table summarizes our operating and reserve data as of and for each of the periods indicated for continuing operations. The table includes the non-GAAP financial measure of PV-10. For a definition of PV-10 and a reconciliation to the standardized measure of discounted future net cash flow, its most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Non-GAAP Financial Measures" below.

		2011		2010		2009
Production						
Oil (Bbls)		694,452		691,574		720,010
Natural gas (Mcf)		8,912,250	3	,088,598	1	,510,500
NGLs (Bbls)		190,151		25,559		7,750
Mcf equivalent (Mcfe)	1	4,219,868	7	,391,396	5	,877,060
Oil and natural gas sales(a)						
Oil sales	\$	63,515	\$	52,577	\$	41,881
Natural gas sales	\$	38,161	\$	13,789	\$	6,460
NGLs sales	\$_	10,203	\$_	858	\$	193
Total	\$	111,879	\$	67,224	\$	48,534
Average sales price(a)						
Oil (\$ per Bbl)	\$	91.35	\$	76.03	\$	58.17
Natural gas (\$ per Mcf)	\$	4.28	\$	4.46	\$	4.28
NGLs (\$ per Bbl)		53.66	\$	33.60	\$	24.90
Mcf equivalent (\$ per Mcfe)	\$	7.87	\$	9.10	\$	8.26
Average production cost						
Mcf equivalent (\$ per Mcfe)	\$	2.33	\$	3.34	\$	3.77
Estimated proved reserves(b)						
Bcf equivalent (Bcfe)		366.2		201.7		125.2
% Oil		13%)	24%		49%
% Proved producing		45%)	38%		51%
PV-10 (millions)	\$	539.6	\$	269.4	\$	190.5
Standardized measure (millions)	\$	413.9	\$	188.1	\$	144.4

- (a) Information excludes the impact of our financial derivative activities.
- (b) The estimates of reserves in the table above conform to the guidelines of the SEC. Estimated recoverable proved reserves have been determined without regard to any economic impact that may result from our financial derivative activities. These calculations were prepared using standard geological and engineering methods generally accepted by the petroleum industry. The estimated present value of estimated proved reserves does not give effect to indirect expenses such as debt service and future income tax expense, asset retirement obligations, or to depletion, depreciation and amortization. The reserve information shown is estimated. The certainty of any reserve estimate is a function of the quality of available geological, geophysical, engineering and economic data, the precision of the engineering and geological interpretation, and judgment. The estimates of reserves, future cash flows and present value are based on various assumptions, and are inherently imprecise. Although we believe these estimates are reasonable, actual future production, cash flows, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from these estimates. Also, the use of a 10% discount factor for reporting purposes may not necessarily represent the most appropriate discount factor, given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

Non-GAAP Financial Measures

We include in this report our calculations of EBITDAX and PV-10, which are non-GAAP financial measures. Below, we provide reconciliations of these non-GAAP financial measures to their most directly comparable financial measure as calculated and presented in accordance with GAAP.

EBITDAX

"EBITDAX" means, for any period, the sum of net income for such period plus the following expenses, charges or income to the extent deducted from or added to net income in such period: interest, income taxes, depreciation, depletion, amortization, unrealized losses from financial derivatives, exploration expenses and other non-cash charges, minus all non-cash income, including but not limited to, income from unrealized financial derivatives, added to net income. EBITDAX, as defined above, is used as a financial measure by our management team and by other users of our financial statements, such as our commercial bank lenders, to analyze such things as:

- Our operating performance and return on capital in comparison to those of other companies in our industry, without regard to financial or capital structure;
- The financial performance of our assets and valuation of the entity without regard to financing methods, capital structure or historical cost basis;
- Our ability to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our stockholders; and
- The viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

EBITDAX is not a calculation based on GAAP financial measures and should not be considered as an alternative to net income (loss) in measuring our performance, nor used as an exclusive measure of cash flow, because it does not consider the impact of working capital growth, capital expenditures, debt principal reductions, and other sources and uses of cash, which are disclosed in our statements of cash flows.

We have reported EBITDAX because it is a financial measure used by our existing commercial lenders, and we believe this measure is commonly reported and widely used by investors as an indicator of a company's operating performance and ability to incur and service debt. You should carefully consider the specific items included in our computations of EBITDAX. While we have disclosed our EBITDAX to permit a more complete

comparative analysis of our operating performance and debt servicing ability relative to other companies, you are cautioned that EBI DAX as reported by us may not be comparable in all instances to EBITDAX as reported by other companies. EBITDAX amounts may not be fully available for management's discretionary use, due to requirements to conserve funds for capital expenditures, debt service and other commitments.

We believe EBITDAX assists our lenders and investors in comparing a company's performance on a consistent basis without regard to certain expenses, which can vary significantly depending upon accounting methods. Because we may borrow money to finance our operations, interest expense is a necessary element of our costs and our ability to generate cash available for distribution. Because we use capital assets, depreciation and amortization are also necessary elements of our costs. Additionally, we are required to pay federal and state taxes, which are necessary elements of our costs. Therefore, any measures that exclude these elements have material limitations.

To compensate for these limitations, we believe it is important to consider both net income determined under GAAP and EBITDAX to evaluate our performance.

The following table presents a reconciliation of our net income to our EBITDAX for each of the periods presented:

	Year Ended December 31, (in thousands)							
	2011	2010	2009	2008	2007			
Net Income (Loss) From Continuing Operations	\$ 18,081	\$ 7,805	\$(16,568)	\$(40,978)	\$(21,682)			
Add Back Depletion, Depreciation, Amortization								
and Accretion	28,361	21,806	25,205	37,904	17,804			
Add Back Non-Cash Compensation Expense	1,601	907	1,557	2,990	211			
Add Back Interest Expense ¹	2,019	1,781	1,602	1,342	5,646			
Add Back Impairment Expense	14,631	8,863	1,625	71,349				
Add Back Exploration Expense	2,507	2,578	2,080	3,261	1,238			
Less Interest Income	(10)	(68)	(7)	(328)	(15)			
Add Back (Gain) Loss on Disposal of Assets	502	(16,395)	427	6,468	(12)			
Add Back Unrealized (Gain) Loss on Financial								
Derivatives	(12,704)	(5,960)	17,558	(43,746)	26,250			
Add Back Noncontrolling Interest Share of Net								
Income (Loss)	7	253	12		6,152			
Add Back (Less) Equity Method EBITDAX	1,259	(85)	6	24	(2)			
Add Back Income Tax Expense (Benefit)	8,270	5,500	(11,002)	(9,167)	(7,365)			
EBITDAX from Continuing Operations	64,524	26,985	22,495	29,119	28,225			
Net Income (Loss) From Discontinued Operations	\$(33,457)	\$ (2,022)	\$ 323	\$ (7,704)	\$ (681)			
Add Back Depletion, Depreciation, Amortization								
and Accretion	85	1	_	1,565	1,819			
Add Back Non-Cash Compensation Expense	24	7						
Add Back Interest Expense	1				-			
Add Back Impairment Expense	13,176	-		8,729				
Add Back Exploration Expense	33,812	2,664		2,198	1,710			
Add Back Loss on Disposal of Assets				41	(173)			
Add Back Unrealized (Gain) Loss on Financial								
Derivatives		-	(558)	558				
Add Back (Less) Income Tax Expense (Benefit)	(15,302)	(1,440)	288	(1,736)	348			
EBITDAX from Discontinued Operations	(1,661)	(790)	53	3,651	3,023			
EBITDAX	\$ 62,863	\$ 26,195	\$ 22,548	\$ 32,770	\$ 31,246			

Includes realized settlements on interest rate swap.

PV-10

The following table shows the reconciliation of PV-10 to our standardized measure of discounted future net cash flows, the most directly comparable measure calculated and presented in accordance with GAAP. PV-10 represents our estimate of the present value, discounted at 10% per annum, of estimated future cash flows of our estimated proved reserves before income tax and asset retirement obligations. Our estimated future cash flows as of December 31, 2009, 2010 and 2011 were determined by using reserve quantities of estimated proved reserves and the periods in which they are expected to be developed and produced based on the prevailing economic conditions. The estimated future production for the years ended December 31, 2009, 2010 and 2011, was priced based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December, without escalation, using \$57.65 per Bbl, \$76.03 per Bbl and \$92.45 per Bbl of oil, respectively, and \$3.866 per MMBtu, \$4.567 per MMBtu and \$4.545 per MMBtu of natural gas, respectively, as adjusted by lease for transportation fees and regional price differentials. NGLs were priced at \$57.65 per Bbl, \$31.71 per Bbl and \$46.34 per Bbl for the years ended December 31, 2009, 2010 and 2011, respectively. Management believes that PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and natural gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. PV-10 should not be considered as an alternative to the standardized measure of discounted future net cash flows as computed under GAAP.

	2011	2010	2009
Reconciliation of standardized measure to PV-10			
PV-10	\$ 539.6	\$269.4	\$190.5
Add: Present value of future income tax discounted at 10%	(119.0)	(64.1)	(30.0)
Add: Present value of future asset retirement obligations discounted at 10%	(18.7)	(17.2)	(16.1)
Standardized measure of discounted future net cash flows	\$ 413.9	\$188.1	<u>\$144.4</u>

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with "Item 6. Selected Financial Data" and the Consolidated Financial Statements and related notes included elsewhere in this report. This discussion contains forward-looking statements reflecting our current expectations and estimates, and assumptions concerning events and financial trends that may affect our future operating results or financial position. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors, including those discussed in the sections entitled "Cautionary Note Regarding Forward-Looking Statements" and "Item 1A. Risk Factors" appearing elsewhere in this report. All financial and operating data presented are the results of continuing operations unless otherwise noted.

Overview of Our Business

We are an independent oil and gas company operating in the Appalachian Basin and the Illinois Basin. In the Appalachian Basin, we are focused on our Marcellus Shale drilling projects and Utica Shale exploration. In the Illinois Basin, in addition to our developmental conventional oil drilling, we are focused on the implementation of enhanced oil recovery on our properties. We pursue a balanced growth strategy of pursuing our higher potential exploration drilling prospects and actively seeking to acquire complementary oil and natural gas properties.

We are headquartered in State College, Pennsylvania, and have regional offices in Bridgeport, Illinois, Butler, Pennsylvania, Seven Fields, Pennsylvania and Carrolton, Ohio.

Our financial results depend upon many factors, particularly the price of oil and gas. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, refinery or pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future oil and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success.

During 2011, we increased our proved reserves base by approximately 81.6%, from 201.7 Bcfe at December 31, 2010. The primary contributing factor to this increase was our continued drilling success in the Appalachian Basin, where we drilled 51.0 gross (25.9 net) wells which also resulted in an increase in production of 92.4%. Amidst our successful drilling endeavors, we successfully drilled two successful test wells, one to the Utica Shale and one to the Burkett Shale, solidifying our belief that there are multiple producing zones underlying our acreage in Butler County, Pennsylvania. We continued to increase our acreage position in the Appalachian Basin during 2011, ending the year with approximately 162,200 gross (93,900 net) acres under leasehold, which includes approximately 15,000 gross acres in Ohio that we believe to be prospective for the liquids-rich portion of the Utica Shale. As of December 31, 2011, our acreage holdings prospective for liquids-rich production accounted for approximately 82.6% of our total net acreage. Through our acreage holdings and successful drilling operations we have been able to expand our available drilling inventory, which now includes 192.9 Bcfe in proved undeveloped reserves covering 90.0 gross proved undeveloped drilling locations. To prepare for our future growth, we have entered into various gathering, processing and sales agreements to ensure market capacity for our projected production.

In 2010, we entered into a joint venture agreement with Sumitomo. In accordance with the agreement, we sold a 15% non-operated interest in our Butler County, Pennsylvania project area and Sumitomo also agreed to lease an additional 9,000 acres in this project area. The leasing arrangement was concluded during 2011; consequently, the ownership percentages in the project area are approximately 70% to us and 30% to Sumitomo. In addition to our Butler County, Pennsylvania project area, we also sold a 20% non-operated interest in our joint

venture area with Williams (discussed below) and a 50% non-operated interest in undeveloped acreage in Fayette and Centre Counties, Pennsylvania. At closing, we received approximately \$99.5 million in cash, which included a reimbursement for leasing expenses incurred subsequent to the effective date of September 1, 2010, in the amount of \$7.6 million, and a reimbursement for drilling related expenses incurred subsequent to the effective date in the amount of approximately \$7.5 million. As a part of the joint venture agreement, Sumitomo agreed to pay 80% of our net drilling and completion expenses up to approximately \$58.8 million. For additional information on the transaction with Sumitomo, see Note 3, *Business and Oil and Gas Property Acquisitions and Dispositions*, to our Consolidated Financial Statements.

In 2009, we entered into a joint venture agreement with Williams. In accordance with the agreement, we sold a 50% working interest in certain oil and gas leases in Centre, Clearfield and Westmoreland Counties, Pennsylvania through a "drill-to-earn" structure. For Williams to earn its 50% interest they were required to bear 90% of all costs and expenses incurred in the drilling and completion of all wells jointly drilled until such time Williams had invested approximately \$74.0 million (approximately \$33.0 million on behalf of us and \$41.0 million for Williams' 50% share of the wells). As of December 31, 2010, Williams had completed its carry obligation and acquired their 50% working interest. Subsequent to the joint venture agreement with Sumitomo, the ownership percentages are approximately 50% to Williams, 40% to us and 10% to Sumitomo. For additional information on the transaction with Williams, see Note 3, *Business and Oil and Gas Property Acquisitions and Dispositions*, to our Consolidated Financial Statements.

Source of Our Revenue

We generate our revenue primarily from the sale of crude oil to refining companies and natural gas to local distribution and pipeline companies. Our operating revenue before the effects of financial derivatives from these operations, and their relative percentages of our total revenue, consisted of the following:

	2011	% of Total	2010	% of Total	2009	% of Total
Sources of Revenue (\$ in thousands):						
Revenue from Oil Sales	\$ 63,515	55.4%	\$52,577	76.5%	\$41,881	86.0%
Revenue from Natural Gas Sales	38,161	33.3%	13,789	20.1%	6,460	13.3%
Revenue from NGL Sales	10,203	8.9%	858	1.2%	193	0.4%
Other	2,727	2.4%	1,539	2.2%	157	0.3%
Total	\$114,606	100.0%	\$68,763	100.0%	\$48,691	100.0%

We have identified the impact of generally volatile commodity prices in the last several years as an important trend that we expect to affect our business in the future. If commodity prices increase, we would expect not only an increase in revenue, but also in the competitive environment for quality drilling prospects, qualified geological and technical personnel and oil field services, including rig availability. Increasing competition in these areas would likely result in higher costs in these areas, and could result in unavailability of drilling rigs, thus affecting the profitability of our future operations. We may not be able to compete successfully in the future with larger competitors in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. In the event of a declining commodity price environment, our revenues would decrease and we would anticipate that the cost of materials and services would decrease as well, although at a slower rate. Decreasing oil or natural gas prices may also make some of our prospects uneconomical to drill.

Principal Components of Our Cost Structure

Our operating and other expenses consist of the following:

• Production and Lease Operating Expenses. Day-to-day costs incurred to bring hydrocarbons out of the ground and to the market together with the daily costs incurred to maintain our producing properties.

Such costs also include workovers, repairs to our oil and gas properties not covered by insurance, and various production taxes that are paid based upon rates set by federal, state, and local taxing authorities.

- General and Administrative Expense. Overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters and regional offices, costs of managing our production and development operations, audit and other professional fees, and legal compliance are included in general and administrative expense. General and administrative expense includes non-cash stock-based compensation expense as part of employee compensation.
- Exploration Expense. Geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory wells, also known as dry holes.
- Interest. We typically finance a portion of our working capital requirements and acquisitions with borrowings under our senior credit facility. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. We may continue to incur significant interest expense as we continue to grow.
- Depreciation, Depletion, Amortization and Accretion. The systematic expensing of the capital costs incurred to acquire, explore and develop natural gas and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense. This also includes the systematic, monthly accretion of the future abandonment costs of tangible assets such as platforms, wells, service assets, pipelines, and other facilities.
- Income Taxes. We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs ("IDC"). We do pay some state income taxes where our IDC deductions do not exceed our taxable income or where state income taxes are determined on another basis. Currently, all of our federal taxes are deferred; however, we have scheduled the timing of reversal of our deferred tax assets and believe we will use all of our net operating loss carryforwards prior to their expiration.

How We Evaluate Our Operations

Our management uses a variety of financial and operational measurements to analyze our performance. These measurements include EBITDAX (a non-GAAP measure), lease operating expenses per Mcf equivalent ("Mcfe"), growth in our proved reserve base, and general and administrative expenses per Mcfe. The following table presents these metrics for continuing operations for each of the three years ended December 31, 2011, 2010 and 2009.

	Performance Measurements					
	Years	Years Ended December 3				
	2011	2010	2009			
EBITDAX (\$ in thousands)	\$64,524	\$26,985	\$22,495			
Production Cost per Mcfe	\$ 2.33	\$ 3.34	\$ 3.77			
Total Estimated Proved Reserves (Bcfe)	366.2	201.7	125.2			
G&A per Mcfe	\$ 1.66	\$ 2.32	\$ 2.70			

EBITDAX

"EBITDAX," a non-GAAP measure, means, for any period, the sum of net income for such period plus the following expenses, charges or income to the extent deducted from or added to net income in such period: interest, income taxes, depreciation, depletion, amortization, unrealized losses from financial derivatives, exploration expenses and other non-cash charges, minus all non-cash income, including but not limited to, income from unrealized financial derivatives, added to net income. EBITDAX, as defined above, is used as a financial measure by our management team and by other users of our financial statements, such as our commercial bank lenders, to analyze such things as:

- Our operating performance and return on capital in comparison to those of other companies in our industry, without regard to financial or capital structure;
- The financial performance of our assets and valuation of the entity, without regard to financing methods, capital structure or historical cost basis;
- Our ability to generate cash sufficient to pay interest costs, support our indebtedness and make cash distributions to our stockholders; and
- The viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

For a definition of EBITDAX and a reconciliation to its most directly comparable financial measure calculated and presented in accordance with GAAP, please see "Non-GAAP Financial Measures."

Production Cost per Mcfe

Production costs are comprised of those expenses which are directly attributable to our producing oil and gas leases, including state and county production taxes, production related insurance, the cost of materials, maintenance, electricity, chemicals, gathering, processing, fuel and the wages of our field personnel. Our production costs per Mcfe are higher than those of many of our peers primarily because of the nature of our oil properties, many of which are mature waterflood properties. Our production cost per Mcfe produced in 2011 was \$2.33 as compared to \$3.34 in 2010 and \$3.77 in 2009. As we continue to develop our non-proved properties, such as the Marcellus Shale, which have a lower operating cost, we believe this metric will continue to decrease on a per unit basis.

Growth in our Proved Reserve Base

We measure our ability to grow our estimated proved reserves over the amount of our total annual production. As we produce oil and gas attributable to our estimated proved reserves, our estimated proved reserves decrease each year by that amount of production. We attempt to replace these produced estimated proved reserves each year through the addition of new estimated proved reserves through our drilling and other property improvement projects and through acquisitions. Our estimated proved reserves have fluctuated since 2009, from 125.2 Bcfe at year end 2009 to 201.7 Bcfe at year end 2010 to 366.2 Bcfe at year end 2011. Our reserve replacement ratio for year end 2009 was approximately 410% based on total production for the year of 5.9 Bcfe and extensions, discoveries and other additions of 24.1 Bcfe. Our reserve replacement ratio for year end 2010 was approximately 1,559% based on total production for the year of 7.3 Bcfe, and extensions, discoveries and other additions of 98.2 Bcfe. Our reserve replacement ratio for year end 2011 was approximately 1,096% based on total production for the year of 14.2 Bcfe, and extensions, discoveries and other additions of 178.7 Bcfe.

Our estimated proved reserve base increased in 2011 when compared to 2010 predominately due to our successful drilling and exploration programs in the Marcellus Shale and the increase in oil prices used for the reserves determination. As of December 31, 2010, we removed all proved undeveloped locations related to our conventional drilling opportunities in the Illinois and Appalachian Basins from our proved reserve totals, which

is in compliance with SEC rules requiring a high degree of confidence that the quantities related to proved undeveloped reserves will be recovered and they are scheduled to be drilled within the next five years. For 2011, our proved reserve base in the Marcellus Shale increased by approximately 112.8%, while our estimated proved reserves in the Illinois Basin increased by 0.5%.

General and Administrative Expenses per Mcfe

Our general and administrative expenses include fees for well operating services, marketing, non-field level employee compensation and related benefits, office and lease expenses, insurance costs and professional fees, as well as other costs and expenses not directly related to field operations. Our management continually evaluates the level of our general and administrative expenses in relation to our production because these expenses have a direct impact on our profitability. In 2011 our general and administrative expenses per Mcfe produced decreased to \$1.66 from \$2.32 in 2010 and from \$2.70 in 2009. As we continue to develop our non-proved properties, we believe this metric will continue to decrease on a per unit basis.

Results of Continuing Operations

General Overview

Operating revenue increased 66.7% for 2011 over 2010. This increase is primarily due to increased oil and gas production in each of our operating regions and higher oil and NGL prices, which were partially offset by lower natural gas prices. For 2011, total production increased 92.4% to 14,220 MMcfe from 7,391 MMcfe in 2010 due to the continued success of our drilling programs, primarily in the Marcellus Shale.

Operating expenses increased \$45.3 million in 2011, or 75.6%, as compared to 2010. Operating expenses are primarily composed of production expenses, general and administrative expenses, gain (loss) on disposal of assets, exploration expenses, impairment of oil and gas properties and depreciation, depletion, amortization and accretion expenses ("DD&A"). The increases in operating expense were primarily due to the growth of our operations, particularly in Butler County, Pennsylvania where we are required to process our gas prior to entry into the sales line. Also contributing to the increase were impairment expenses, which were approximately \$5.8 million higher than in 2010 primarily due to the write-down of our conventional natural gas properties in the Appalachian Basin. Approximately \$16.4 million of the increase was due to the gain on sale recognized as a result of the Sumitomo transaction in 2010.

Comparison of the Year Ended December 31, 2011 to the Year Ended December 31, 2010

Oil and gas revenue for the years ended December 31, 2011 and 2010 is summarized in the following table:

	December 31,						
		2011		2010		Change	%
Oil and Gas Revenue (\$ in thousands):							
Oil sales revenue	\$	63,515	\$	52,577	\$	10,938	20.8%
Oil derivatives realized		(670)		(3,861)		3,191	82.6%
Total oil revenue and derivatives realized	\$	62,845	\$	48,716	\$	14,129	29.0%
Gas sales revenue	\$	38,161	\$	13,789	\$	24,372	176.7%
Gas derivatives realized		6,882		4,667		2,215	47.5%
Total gas revenue and derivatives realized	\$	45,043	\$	18,456	\$	26,587	144.1%
Total NGL revenue	\$	10,203	\$	858	\$	9,345	1,089.2%
Consolidated sales	\$	111,879	\$	67,224	\$	44,655	66.4%
Consolidated derivatives realized		6,212		806		5,406	670.7%
Total oil and gas revenue and derivatives							
realized	\$	118,091	\$	68,030	\$	50,061	73.6%
Total Mcfe production	1	4,219,868	7	,391,396	6	,828,472	92.4%
derivatives	\$	8.30	\$	9.20	\$	(0.90)	(9.7%)

Average realized price received for oil and gas during 2011 was \$8.30 per Mcfe, a decrease of 9.7%, or \$0.90 per Mcfe, from the prior year. The average realized price for oil, including the effects of derivatives, in 2011 increased 28.5% or \$20.05 per barrel, whereas the average realized price for natural gas, including the effects of derivatives, decreased 15.4%, or \$0.92 per Mcf, from 2010. Our derivative activities effectively increased net realized prices by \$0.44 per Mcfe in 2011 and \$0.11 per Mcfe in 2010.

Production volume for 2011 increased 92.4% from 2010 primarily due to the success of our Marcellus Shale horizontal drilling plan in the Appalachian Basin, where production increased approximately 210.2%, or 6.8 Bcfe. Our production for 2011 averaged approximately 38,959 Mcfe per day of which 29.3% was attributable to the Illinois Basin and 70.7% to the Appalachian Basin.

Statements of Operations for the years ended December 31, 2011 and 2010 are as follows:

	December 31,				
	2011	2010	Change	%	
OPERATING REVENUE					
Oil, Natural Gas and NGL Sales	\$111,879	\$ 67,224	\$ 44,655	66.4%	
Other Revenue	2,727	1,539	1,188	77.2%	
TOTAL OPERATING REVENUE	114,606	68,763	45,843	66.7%	
OPERATING EXPENSES					
Production and Lease Operating Expense	33,116	24,656	8,460	34.3%	
General and Administrative Expense	23,636	17,141	6,495	37.9%	
(Gain) Loss on Disposal of Assets	502	(16,395)	16,897	103.1%	
Impairment Expense	14,631	8,863	5,768	65.1%	
Exploration Expense	2,507	2,578	(71)	(2.8%)	
Depreciation, Depletion, Amortization and Accretion	28,361	21,806	6,555	30.1%	
Other Operating Expense	2,569	1,341	1,228	91.6%	
TOTAL OPERATING EXPENSES	105,322	59,990	45,332	75.6%	
INCOME (LOSS) FROM OPERATIONS	9,284	8,773	511	5.8%	
OTHER INCOME (EXPENSE)					
Interest Income	10	68	(58)	(85.3%)	
Interest Expense	(2,019)	(1,070)	(949)	88.7%	
Gain (Loss) on Derivatives, Net	18,916	6,055	12,861	212.4%	
Other Income (Expense)	79	(321)	400	124.6%	
Gain (Loss) on Equity Method Investments	81	(200)	281	140.5%	
TOTAL OTHER INCOME (EXPENSE)	17,067	4,532	12,535	276.6%	
INCOME (LOSS) FROM CONTINUING OPERATIONS					
BEFORE INCOME TAX	26,351	13,305	13,046	98.1%	
Income Tax Benefit (Expense)	(8,270)	(5,500)	(2,770)	50.4%	
INCOME (LOSS) FROM CONTINUING OPERATIONS	18,081	7,805	10,276	131.7%	
Income (Loss) From Discontinued Operations, Net of Income					
Taxes	(33,457)	(2,022)	(31,435)	1,554.6%	
NET INCOME (LOSS)	(15,376)	5,783	(21,159)	(365.9%)	
Net Loss Attributable to Noncontrolling Interests	(7)	(253)	246	(97.2%	
NET INCOME (LOSS) ATRRIBUTABLE TO REX					
ENERGY	\$(15,369)	\$ 6,036	\$(21,405)	(354.6%)	
				-	

Other Revenue for 2011 of approximately \$2.7 million increased \$1.2 million, or 77.2%, from 2010. During 2010, we entered into a joint venture that specializes in the sourcing and transportation of water in the

Marcellus Shale regions of the Appalachian Basin. Revenues earned by this joint venture, Water Solutions Holdings, LLC ("Water Solutions"), of which we own 80%, have been classified as Other Revenue and did not exist prior to 2010.

Production and Lease Operating Expense increased approximately \$8.5 million, or 34.3%, in 2011 from 2010. The increase is primarily due to processing and gathering fees incurred in our Butler County, Pennsylvania operating region. We produce wet gas in this region, which requires processing before it can be sold. As such, we jointly constructed a cryogenic gas processing plant for which we pay fees to have our gas transported and processed before sale. We incurred approximately \$4.6 million in expenses related to processing and gathering during 2011 and approximately \$0.3 million in 2010. Also contributing to our increased expenses was the growth of our Appalachian Basin operations, where we placed into service 51.0 gross (25.9 net) wells in 2011.

General and Administrative Expense of approximately \$23.6 million for 2011 increased approximately \$6.5 million, or 37.9%, from 2010. The increase in general and administrative costs is attributable to legal expenses, severance wages and an overall increase in headcount. We incurred \$2.5 million in legal costs associated with the settlement of our leasing lawsuit in Westmoreland County, Pennsylvania. During 2011, we entered into separation agreements with several employees for which we incurred approximately \$1.0 million in severance costs. The remainder of the increase during 2011 is primarily attributable to our continued efforts to hire and retain high quality personnel. We have incurred higher recruiting, wages and benefits costs to achieve this goal, which includes approximately \$1.6 million in non-cash compensation in 2011 as compared to \$0.9 million in 2010.

(Gain) Loss on Disposal of Assets for 2011 was a loss of approximately \$0.5 million as compared to a gain of \$16.4 million for 2010. From time to time, we sell or otherwise dispose of certain fixed assets and wells that are no longer effectively used by us, and a gain or loss may be recognized when such an asset is sold.

Impairment Expense increased to \$14.6 million in 2011 from \$8.9 million, or 64.0%, in 2010. We evaluate impairment of our properties when events occur that indicate that the carrying value of these properties may not be recoverable. During 2011 we incurred approximately \$11.6 million of impairment expense related to conventional shallow natural gas properties in the Appalachian Basin due to their estimated fair value being less than their carrying value as of December 31, 2011. These wells are characterized as older wells that produce at much lower rates than the unconventional shale plays. While they are less capital intensive and have lower operating costs, their lower production levels combined with lower commodity pricing make them susceptible to impairment write downs. The remainder of our impairment in 2011 was primarily due to the expiration of leased acreage. During 2010, impairment expense was primarily related to two test wells in Clearfield County, Pennsylvania. We determined that the carrying value of these two test wells, which were in various stages of drilling and completion, was not recoverable due to a lack of a sales outlet and no then-current plans by us to complete the wells for commercial production. We periodically evaluate the capitalized costs associated with properties that are outside of our current scope of operations as to their recoverability based on changes brought about by economic factors and potential shifts in our business strategy. As economic and strategic conditions change and we continue to develop unproved properties, our estimates of impairment will likely change and we may increase or decrease expense.

Exploration Expense of oil and gas properties for 2011 decreased approximately \$0.1 million from \$2.6 million in 2010. Exploration costs incurred by us during 2011 and 2010 were primarily due to delay rental payments on undeveloped acreage and seismic and micro-seismic activities on our properties.

Depletion, Depreciation, Amortization and Accretion Expense of approximately \$28.4 million for 2011 increased approximately \$6.6 million, or 30.1%, from 2010. Depletion expenses incurred during 2010 were lower than what would normally be expected primarily due to the carry obligations by our joint venture partners, whereby our partners would fund the majority of the cost to drill and complete wells to earn their share of the working interest. We expect future depletion to trend more in line with production as the carry obligations have been expended, pending any future carry obligations.

Other Operating Expense for 2011 totaled approximately \$2.6 million. These costs are comprised of operating expenses incurred in connection with Water Solutions. Water Solutions is a subsidiary of which we own 80% and fully consolidate the results of operations. This entity did not have operating expense prior to 2010.

Interest Expense, net of Interest Income, for 2011 was approximately \$2.0 million as compared to \$1.0 million for 2010. The increase in interest expense, net of interest income, was primarily due to a higher average outstanding balance on our Senior Credit Facility.

Gain (Loss) on Derivatives, net for 2011 was a gain of approximately \$18.9 million as compared to \$6.1 million for 2010. This change was attributable to the volatility of oil and gas commodity prices in the marketplace along with changes in our portfolio of outstanding collars and swap derivatives. Losses from derivative activities generally reflect higher oil and gas prices in the marketplace than were in effect at the time we entered into a derivative contract, while gains would suggest the opposite. Our derivative program is designed to provide us with greater predictability of future cash flows at expected levels of oil and gas production volumes given the highly volatile oil and gas commodities market.

Net Income (Loss) Attributable to Rex Energy for 2011 was a loss of approximately \$15.4 million, as compared to net income of approximately \$6.0 million for 2010 as a result of the factors discussed above.

Comparison of the Year Ended December 31, 2010 to the Year Ended December 31, 2009

Oil and gas revenue for the years ended December 31, 2010 and 2009 is summarized in the following table:

	December 31,					
	2010		2009		Change	%
Oil and Gas Revenue (\$ in thousands):						
Oil sales revenue	\$	52,577	\$	41,881	10,696	25.5%
Oil derivatives realized(a)		(3,861)		2,626	(6,487)	(247.0%)
Total oil revenue and derivatives realized	\$	48,716	\$	44,507	4,209	9.5%
Gas sales revenue	\$	13,789	\$	6,460	7,329	113.5%
Gas derivatives realized		4,667		3,216	1,451	45.1%
Total gas revenue and derivatives realized	\$	18,456	\$	9,676	8,780	90.7%
Total NGL revenue	\$	858	\$	193	665	344.6%
Consolidated sales	\$	67,224	\$	48,534	18,690	38.5%
Consolidated derivatives realized		806		5,842	(5,036)	(86.2%)
Total oil and gas revenue and derivatives realized	\$	68,030	\$	54,376	13,654	25.1%
Total Mcfe production	7	,391,396	5	,877,060	1,514,336	25.8%
derivatives	\$	9.20	\$	9.25	(0.05)	(0.5%)

⁽a) 2009 oil derivatives realized excludes approximately \$4.6 million in proceeds that were received upon the early settlement of oil hedges relating to the 2011 calendar year.

Average realized price received for oil and gas during 2010 was \$9.20 per Mcfe, a decrease of 0.5%, or \$0.05 per Mcfe, from the prior year. The average realized price for oil, including the effects of derivatives, in 2010 increased 14.0% or \$8.63 per barrel, whereas the average realized price for natural gas, including the effects of derivatives, decreased 6.8%, or \$0.43 per Mcf, from 2009. Our derivative activities effectively increased net realized prices by \$0.11 per Mcfe in 2010 and \$0.99 per Mcfe in 2009.

Production volume for 2010 increased 25.8% from 2009 primarily due to the success of our Marcellus Shale horizontal drilling plan in the Appalachian Basin, where production increased approximately 108%, or 1.7 Bcfe. Our production for 2010 averaged approximately 20,250 Mcfe per day of which 56.1% was attributable to the Illinois Basin and 43.9% to the Appalachian Basin.

Statements of Operations for the years ended December 31, 2010 and 2009 are as follows:

	December 31,				
	2010	2009	Change	%	
OPERATING REVENUE					
Oil, Natural Gas and NGL Sales	\$ 67,224	\$ 48,534	\$ 18,690	38.5%	
Other Revenue	1,539	157	1,382	880.3%	
TOTAL OPERATING REVENUE	68,763	48,691	20,072	41.2%	
OPERATING EXPENSES	·				
Production and Lease Operating Expense	24,656	22,157	2,499	11.3%	
General and Administrative Expense	17,141	15,858	1,283	8.1%	
(Gain) Loss on Disposal of Assets	(16,395)	427	(16,822)	(3,939.6%)	
Impairment Expense	8,863	1,625	7,238	445.4%	
Exploration Expense	2,578	2,080	498	23.9%	
Depreciation, Depletion, Amortization and Accretion	21,806	25,205	(3,399)	(13.5%)	
Other Operating Expense	1,341		1,341	100.0%	
TOTAL OPERATING EXPENSES	59,990	67,352	(7,362)	(10.9%)	
INCOME (LOSS) FROM OPERATIONS	8,773	(18,661)	27,434	147.0%	
OTHER INCOME (EXPENSE)					
Interest Income	68	7	61	871.4%	
Interest Expense	(1,070)	(833)	(237)	28.5%	
Gain (Loss) on Derivatives, Net	6,055	(7,913)	13,968	(176.5%)	
Other Income (Expense)	(321)	(161)	(160)	99.4%	
Gain (Loss) on Equity Method Investments	(200)	(9)	(191)	2,122.2%	
TOTAL OTHER INCOME (EXPENSE)	4,532	(8,909)	13,441	150.9%	
INCOME (LOSS) FROM CONTINUING OPERATIONS					
BEFORE INCOME TAX	13,305	(27,570)	40,875	(148.3%)	
Income Tax Benefit (Expense)	(5,500)	11,002	(16,502)	(150.0%)	
INCOME (LOSS) FROM CONTINUING OPERATIONS	7,805	(16,568)	24,373	(147.1%)	
Income (Loss) From Discontinued Operations, Net of Income					
Taxes	(2,022)	323	(2,345)	_(726.0%)	
NET INCOME (LOSS)	5,783	(16,245)	22,028	(135.6%)	
Net Loss Attributable to Noncontrolling Interests	(253)	(12)	(241)	2,008.3%	
NET INCOME (LOSS) ATRRIBUTABLE TO REX					
ENERGY	\$ 6,036	\$(16,233)	\$ 22,269	(137.2%)	

Other Revenue for 2010 of approximately \$1.5 million increased \$1.4 million, or 880%, from 2009. These amounts were attributable to the operations of Water Solutions, our 80% owned joint venture that specializes in the sourcing and transportation of water in the Marcellus Shale regions of the Appalachian Basin. Revenues earned by Water Solutions were classified as Other Revenue in 2010 and did not exist prior to 2010.

Production and Lease Operating Expense increased approximately \$2.5 million, or 11.3%, in 2010 from 2009. The increase in expense was primarily due to seasonal repair and maintenance work being performed in our Illinois Basin operations. These repair and maintenance activities were delayed during 2009 due, in part, to

periods of depressed oil prices during the year. Also contributing to our higher production expenses during the year was the continued expansion of our Marcellus Shale operations, where we began to incur costs to transport and process our natural gas in our Butler County, Pennsylvania project area. Lease operating expense per Mcfe decreased approximately 11.4% from 2009 to \$3.34 per Mcfe in 2010, which was the result of our increased production.

General and Administrative Expense of approximately \$1.1 million for 2010 increased approximately \$1.3 million, or 8.1%, from 2009. These expenses increased from 2009 to 2010 primarily due to expenses recognized with respect to Water Solutions, for which we fully consolidate the results of operations. This entity did not begin operations until December 2009. We also incurred additional G&A expenses in 2010 for legal costs incurred in connection with the Sumitomo transaction, recruiting and relocation expenses associated with the hiring of certain executives and senior management, and in connection with an increase in our overall headcount.

(Gain) Loss on Disposal of Assets for 2010 was a gain of approximately \$16.4 million as compared to a loss \$0.4 million for 2009. From time to time, we sell or otherwise dispose of certain fixed assets and wells that are no longer effectively used by us, and a gain or loss may be recognized when such an asset is sold. The gain in 2010 was primarily due to the Sumitomo joint venture transaction while the loss incurred during 2009 was a result of the disposal of our Southwest Region assets.

Impairment Expense increased to \$8.9 million in 2010 from \$1.6 million in 2009. We evaluate impairment of our properties when events occur that indicate that the carrying value of these properties may not be recoverable. During 2010, we determined that the carrying value of two of our test wells, which were in various stages of drilling and completion, in Clearfield County, Pennsylvania, were not recoverable due to a lack of a sales outlet and no then-current plans by us to complete the wells for commercial production. In addition, the capitalized costs associated with properties that are outside of our current scope of operations are periodically evaluated as to their recoverability based on changes brought about by economic factors and potential shifts in our business strategy. As economic and strategic conditions change and we continue to develop unproved properties, our estimates of impairment will likely change and we may increase or decrease expense.

Exploration Expense of oil and gas properties for 2010 increased to approximately \$2.6 million from \$2.1 million in 2009. Exploration costs incurred by us during 2010 and 2009 were primarily due to delay rental payments on undeveloped acreage and seismic and micro-seismic activities on our properties.

Depletion, Depreciation, Amortization and Accretion Expense of approximately \$21.8 million for 2010 decreased approximately \$3.4 million, or 13.5%, from 2009. This decrease can be primarily explained by the upward revision in the estimated lives of our estimated proved reserves. We calculate our depletion on a units-of-production basis, which decelerated in relation to our higher estimated proved reserves base.

Other Operating Expense for 2010 totaled approximately \$1.3 million. These costs were comprised of operating expenses incurred in connection with Water Solutions. This entity did not have operating expense prior to 2010.

Interest Expense, net of Interest Income, for 2010 was approximately \$1.0 million as compared to \$0.8 million for 2009. The increase in interest expense, net of interest income, was primarily due to our higher average outstanding balance on our Senior Credit Facility.

Gain (Loss) on Derivatives, net for 2010 was a gain of approximately \$6.1 million as compared to a loss of \$7.9 million for 2009. The change was attributed to the volatility of oil and gas commodity prices in the marketplace along with changes in our portfolio of outstanding collars and swap derivatives. Losses from derivative activities generally reflect higher oil and gas prices in the marketplace than were in effect at the time we entered into a derivative contract, while gains would suggest the opposite. Our derivative program is designed to provide us with greater reliability of future cash flows at expected levels of oil and gas production volumes given the highly volatile oil and gas commodities market.

Other Expense increased by \$0.2 million to approximately \$0.3 million in 2010. The increase in Other Expense was primarily attributable to expenses incurred in connection with ensuring the pipeline integrity of a gathering system contributed to our Keystone Midstream Services, LLC joint venture, of which we are the 28% owner.

Net Income (Loss) Attributable to Rex Energy for 2010 was income of approximately \$6.0 million, as compared to a net loss of approximately \$16.2 million for 2009 as a result of the factors discussed above.

Capital Resources and Liquidity

Our primary financial resource is our base of oil and gas reserves. During 2011, \$275.4 million of capital, which excludes our joint venture investments, was expended on drilling projects, facilities and related equipment and acquisitions of unproved acreage. The capital program was funded by net cash flow from operations and through borrowings on our Senior Credit Facility and our second lien credit agreement. Our 2012 capital budget of \$155.3 million is expected to continue to be funded primarily by cash flow from operations, non-core asset sales and borrowings under our credit agreements. We currently believe that we have sufficient liquidity and cash flow to meet our obligations for the next twelve months; however, a significant drop in commodity prices, particularly natural gas, or a reduction in production or reserves could adversely affect our ability to fund capital expenditures and meet our financial obligations. Also, our obligations may change due to acquisitions, divestitures and continued growth. We may also elect to issue additional shares of stock, subordinated notes or other securities to fund capital expenditures, acquisitions, extend maturities or to repay debt. On February 6, 2012, we completed an underwritten public offering of 8,050,000 shares of our common stock, which included 1,050,000 shares of common stock issued upon the full exercise of the underwriters' over-allotment option, at a public offering price of \$9.25 per share. The net proceeds of the transaction are expected to be approximately \$70.6 million, after deducting underwriting discounts, commissions and estimated offering expense. We have used the proceeds of the offering to repay borrowings under our Senior Credit Facility.

Our ability to fund our capital expenditure program is dependent upon the level of product prices and the success of our exploration program in replacing our existing oil and gas reserves. If product prices decrease, our operating cash flow may decrease and the banks may require additional collateral or reduce our borrowing base, thus reducing funds available to fund our capital expenditure program. The effects of product prices on cash flow can be mitigated through the use of commodity derivatives. If we are unable to replace our oil and gas reserves through our acquisitions, development or exploration programs, we may also suffer a reduction in our operating cash flow and access to funds under the senior credit facility. Under extreme circumstances, product price reductions or exploration drilling failures could allow the banks to seek to foreclose on our oil and gas properties, thereby threatening our financial viability.

Our cash flow from operations is driven by commodity prices and production volumes. Prices for oil and gas are driven by, among other things, seasonal influences of weather, national and international economic and political environments and, increasingly, from heightened demand for hydrocarbons from emerging nations. Our working capital is significantly influenced by changes in commodity prices, and significant declines in prices could decrease our exploration and development expenditures. Cash flows from operations and borrowings from our senior credit facility have been primarily used to fund exploration and development of our oil and gas interests. As of December 31, 2011, we had \$80.0 million available for borrowing under our senior credit facility of \$255.0 million and \$50.0 million available for borrowing under our second lien credit agreement of \$100.0 million. As of December 31, 2011, we were in compliance with all required debt covenants.

In addition, we have utilized two joint venture agreements with Sumitomo and Williams to supplement our capital outlay to assist in sustaining our growth prospects. Through the Sumitomo PEA, we received approximately \$99.5 million in cash in addition to approximately \$58.8 million in drilling expenses in our joint venture project areas. As of December 31, 2011, Sumitomo fulfilled its drilling carry obligation in full. In addition to the drilling carry, Sumitomo has also agreed to pay to us a management fee of \$150 per acre for leases acquired in our Butler County, Pennsylvania project area.

Financial Condition and Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

The following table summarizes our sources and uses of funds for the periods noted:

		rs Ended Dec in Thousands	
	2011	2010	2009
Cash flows provided by operating activities	\$ 64,507	\$ 18,016	\$ 20,774
Cash flows used in investing activities	(276,574)	(78,835)	(30,061)
Cash flows provided by financing activities	212,855	66,245	7,823
Net increase (decrease) in cash and cash equivalents	\$ 788	\$ 5,426	\$ (1,464)

Net cash provided by operating activities increased by approximately \$46.5 million in 2011 when compared to 2010, to \$64.5 million. This increase is primarily due to increased oil and natural gas production, in addition to higher crude oil prices as compared to 2010. Partially offsetting these increases were higher production and G&A costs. Net cash provided by operating activities decreased by approximately \$2.8 million in 2010 when compared to 2009, to \$18.0 million. In 2010, cash flows decreased primarily due to the receipt of approximately \$4.6 million in 2009 related to the early settlement of certain oil derivatives that were originally scheduled to be settled in 2011. In addition, we experienced higher costs related to production and lease operating expenses and general and administrative expenses. Higher natural gas production partially offset these declines in operating cash flows.

Net cash used in investing activities increased by approximately \$197.7 million in 2011 when compared to 2010, to \$276.6 million. Approximately \$118.8 million of this increase is due to our growth and expansion during the year as we drilled, completed and placed into service wells in our Appalachian Basin region. Also contributing to the increase in net investing were lower proceeds on sale of assets of \$76.5 million during 2011, which was primarily due to the Sumitomo joint venture that occurred in 2010. Net cash used in investing activities increased by approximately \$48.8 million in 2010 when compared to 2009, to \$78.8 million. During 2009, we decreased our normal development activities and increased our focus on more strategic projects, such as Marcellus Shale exploration. During 2010, our investment activity increased as we expanded our exploration of the Marcellus Shale in the Appalachian Basin and the Niobrara formation in the DJ Basin. Partially offsetting our expenditures in 2010 were proceeds received upon the closing of our joint venture with Sumitomo, where we received cash in exchange for a partial interest in wells, acreage and other equipment.

Net cash provided by financing activities increased by approximately \$146.6 million in 2011 when compared to 2010, to \$212.9 million. During 2011, we increased our borrowings under our credit agreements by \$155.0 million and reduced repayments of debt by \$73.0 million. Net cash provided by financing activities increased by approximately \$58.4 million in 2010 when compared to 2009, to \$66.2 million. During 2010, we received net proceeds from the issuance of common stock of approximately \$80.2 million. This increase in cash flow was partially offset by net repayments of long-term debt of approximately \$13.0 million in 2010 as compared to net proceeds in 2009 of approximately \$8.0 million.

Effects of Inflation and Changes in Price

Our results of operations and cash flows are affected by changing oil and natural gas prices. If the price of oil and natural gas increases or decreases, there could be a corresponding increase or decrease in our operating costs, as well as an increase or decrease in revenues. Inflation has had a minimal effect on us.

Critical Accounting Policies and Recent Accounting Pronouncements

The preparation of financial statements in conformity with United States generally accepted accounting principles ("GAAP") requires management to make estimates and assumptions that affect the reported amounts

of assets and liabilities and disclosures of contingencies at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates include volumes of oil and natural gas reserves used in calculating depletion of proved oil and natural gas properties, future cash flows, asset retirement obligations, impairment (when applicable) of undeveloped properties, the collectability of outstanding accounts receivable, fair values of financial derivative instruments, contingencies and the results of current and future litigation. Oil and natural gas estimates, which are the basis for units-of-production depletion, have numerous inherent uncertainties. The certainty of any reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Subsequent drilling results, testing and production may justify revision of such estimates. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. In addition, reserve estimates are vulnerable to changes in wellhead prices of crude oil and natural gas. These prices have been volatile in the past and are expected to be volatile in the future.

The significant estimates are based on current assumptions that may be materially affected by changes in future economic conditions such as the market prices received for sales of oil and natural gas, interest rates, and our ability to generate future income. Future changes in these assumptions may materially affect these significant estimates in the near term.

Natural Gas and Oil Reserve Quantities

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. For the years ended December 31, 2011 and 2010, Netherland Sewell and Associates, Inc. ("NSAI") prepared a consolidated reserve and economic evaluation of our proved oil and gas reserves. These engineers were selected for their geographic expertise and their historical experience in engineering certain properties. The technical persons responsible for preparing the estimates of our proved reserves meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis. The preparation of our proved reserve estimates are completed in accordance with our internal control procedures, which include the verification of input data used by NSAI, as well as intense management review and approval.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Estimates of our crude oil and natural gas reserves, and the projected cash flows derived from these reserve estimates, are prepared by our engineers in accordance with guidelines established by the SEC, including the rule revisions designed to modernize the oil and gas company reserves reporting requirements and which we adopted effective December 31, 2009. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and natural gas reserves. The certainty of our reserve estimates is a function of many factors, including the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. Any of the assumptions inherent in these factors could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of natural gas and oil eventually recovered. The independent reserve engineer estimates reserves annually on December 31. This annual estimate results in a new DD&A rate, which we use for the preceding fourth quarter after adjusting for fourth quarter production.

Derivative Instruments

We use put and call options (collars), fixed rate swap contracts, swaptions, puts and put spreads to manage price risks in connection with the sale of oil and natural gas. We have also, in the past, used interest rate swap agreements to manage interest rate risks associated with our variable rate credit facility. We have established the fair value of all derivative instruments using estimates determined by our counterparties and other third party providers. These values are based upon, among other things, future prices, volatility, time to maturity and credit risk. The values we report in our consolidated financial statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

We report our derivative instruments at fair value and include them in the Consolidated Balance Sheets as assets or liabilities. The accounting for changes in fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. We do not designate our derivatives as hedging instruments, therefore, any changes in fair value are recognized immediately in earnings.

Oil and Natural Gas Property, Depreciation and Depletion

We account for natural gas and oil exploration and production activities under the successful efforts method of accounting. Proved developed natural gas and oil property acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are assessed periodically on a property-by-property basis, and any impairment in value is recognized. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved natural gas and oil properties. Natural gas and oil exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. Costs to develop estimated proved reserves, including the costs of all development well and related equipment used in the production of natural gas and oil, are capitalized.

Depletion is calculated using the unit-of-production method. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. We periodically review estimated proved reserve estimates and make changes as needed to depletion expenses to account for new wells drilled, acquisitions, divestitures and other events which may have caused significant changes in our estimated proved reserves. The costs of unproved properties are withheld from the depletion base until such time as they are proved. When estimated proved reserves are assigned, the cost of the property is added to costs subject to depletion calculations. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is allocated to the associated producing properties as the undeveloped acreage is developed. Individually significant non-producing properties are periodically assessed for impairment of value. Service properties, equipment and other assets are depreciated using the straight-line method over their estimated useful lives of three to 30 years.

When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and oil prices, operating costs, anticipated production from estimated proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. When evaluating our unproved oil and gas properties, we utilize active market prices for similar acreage to use as a comparison tool against the carrying value of our properties. If the active market prices for similar acreage do not support our carrying values we then utilize estimates of future value that will be created from the future development of these properties. If future estimated fair value of these properties is lower than the capitalized cost, the capitalized cost is reduced to the estimated future fair value. We recognized

approximately \$14.6 million, \$8.9 million and \$1.6 million of impairment from continuing operations on certain oil and gas proper as for the years ending December 31, 2011, 2010 and 2009, respectively. We recorded these charges as Impairment Expense on our Consolidated Statements of Operations. For additional information, see Note 17, *Impairment Expense*, to our Consolidated Financial Statements.

Expenditures for repairs and maintenance to sustain production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Expenditures to construct facilities or increase the productive capacity from existing reservoirs are capitalized.

Upon the sale or retirement of a proved natural gas or oil property, or an entire interest in unproved leaseholds, the cost and related accumulated DD&A are removed from the property accounts and the resulting gain or loss is recognized. For sales of a partial interest in unproved leaseholds for cash or cash equivalents, sales proceeds are first applied as a reduction of the original cost of the entire interest in the property and any remaining proceeds are recognized as a gain.

Deferred Financing Costs and Other Assets—Net

At December 31, 2011, our intangible assets from continuing operations consisted of \$3.3 million, which is primarily made up of loan costs that are amortized using the straight line method over their respective estimated lives, which is, on average, three to five years. We amortize any costs incurred to renew or extend the terms of existing intangible assets over the contract term or estimated useful life, as applicable, using the straight-line method. For the years ended December 31, 2011, 2010, and 2009, we recorded amortization expense from continuing operations of \$0.8 million, \$0.5 million and \$0.4 million, respectively.

Future Abandonment Cost

Future abandonment costs are recognized as obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the asset. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which the natural gas or oil well is acquired or drilled. The future abandonment cost is capitalized as part of the carrying amount of our natural gas and oil properties at its fair value. The liability is then accreted each period until the liability is settled or the natural gas or oil well is sold, at which time the liability is reversed. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost.

Deferred Income Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed several months after the close of a calendar year, tax returns are subject to audit which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences. We routinely evaluate deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when we believe that certain of these assets are not likely to be realized.

We may be challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions in our various income tax returns. Although we believe that we have adequately provided for all taxes, gains or losses could occur in the future due to changes in estimates or resolution of outstanding tax matters.

Contingent Liabilities

A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable and the cost or range of cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, we often must estimate the amount of such losses. In many cases, our judgment is based on the input of our legal advisors and on the interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. We monitor known and potential legal, environmental and other contingent matters and make our best estimate of when to record losses for these matters based on available information. We have recognized an accrued liability of approximately \$0.1 million at December 31, 2011 for the estimated cost of pending litigation matters.

Stock-based Compensation

We recognize in the Consolidated Financial Statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We use a standard option pricing model (i.e. Black-Scholes) to measure the fair value of employee stock options and stock appreciation rights.

The benefits associated with the tax deductions in excess of recognized compensation cost are reported as a financing cash flow. This requirement reduces net operating cash flows and increases net financing cash flows. We recognize compensation costs related to awards with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award were, in-substance, multiple awards.

Recent Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*. ASU 2011-11 provides new disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS and U.S. GAAP. The amendment requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods, including retrospective application for all comparative periods presented. Although we currently are not engaged in any arrangements that would be effected by these disclosure requirements, we believe that ASU 2011-11 may have a material impact on future disclosures pending our entrance into an offsetting arrangement.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. ASU 2011-04 generally provides a uniform framework for fair value measurements and related disclosures between GAAP and International Financial Reporting Standards ("IFRS"). Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements, quantitative information about unobservable inputs used, a description of the valuation process used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a nonfinancial asset that is different from the asset's highest and best use, the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required, the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosures of all transfers between Level 1 and Level 2 of the fair value hierarchy. This update is effective for annual and interim periods beginning on or after December 31, 2011. We adopted ASU 2011-04 on January 1, 2012, with no material impact.

In December 2010, the FASB issued ASU 2010-29, *Disclosure of Supplementary Pro Forma Information for Business Combinations* ("ASU 2010-29"). The amendments to the codification clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Additionally, the supplemental pro forma disclosures under Topic 805 have been expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments in ASU 2010-29 are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Although we have not entered into any significant business combinations in our recent history, we believe that ASU 2010-29 may have a material impact on future disclosures depending on the size and nature of any future business combinations that we may enter into. We adopted ASU 2010-29 on January 1, 2011, with no material impact.

Volatility of Oil and Natural Gas Prices

Our revenues, future rate of growth, results of operations, financial condition and ability to borrow funds or obtain additional capital, as well as the carrying value of our properties, are substantially dependent upon prevailing prices of oil and natural gas.

We account for our natural gas and oil exploration and production activities under the successful efforts method of accounting (for additional information, see Note 2, *Summary of Significant Accounting Policies*, of our Consolidated Financial Statements).

To mitigate some of our commodity price risk we engage periodically in certain other limited derivative activities, including price swaps and costless collars, to establish some price floor protection.

For the twelve-month period ended December 31, 2011, the net realized gain on oil and natural gas derivatives was approximately \$6.2 million. For the twelve-month period ended December 31, 2010, the net realized gain on oil and natural gas derivatives was approximately \$0.1 million.

For the twelve month period ended December 31, 2011, the net unrealized gain on oil and natural gas derivatives was approximately \$12.7 million, as compared to a net unrealized gain of approximately \$6.0 million on oil and natural gas derivatives for 2010. The net unrealized gains and losses are reported as Gain (Loss) on Derivatives, net in the Consolidated Statements of Operations.

While the use of derivative arrangements limits the downside risk of adverse price movements, it may also limit our ability to benefit from increases in the prices of oil and natural gas. We enter into the majority of our derivative transactions with four counterparties and have a netting agreement in place with those counterparties. We do not obtain collateral to support the agreements, but we believe our credit risk is currently minimal on these transactions. Under these arrangements, payments are received or made based on the differential between a fixed and a variable commodity price. These agreements are settled in cash at expiration or exchanged for physical delivery contracts. In the event of nonperformance, we would be exposed again to price risk. We have additional risk of financial loss because the price received for the product at the actual physical delivery point may differ from the prevailing price at the delivery point required for settlement of the derivative transaction. Moreover, our derivative arrangements generally do not apply to all of our production, and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivatives will vary from time to time.

For a summary of our current oil and natural gas derivative positions at December 31, 2011, refer to Note 11, *Fair Value of Financial Instruments and Derivative Instruments*, of our Consolidated Financial Statements.

Contractual Obligations

In addition to our capital expenditure program, we are committed to making cash payments in the future on various types of contracts and obligations. As of December 31, 2011, we do not have any off-balance sheet debt or other such unrecorded obligations and we have not guaranteed the debt of any other party. The table below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2011. In addition to the contractual obligations listed in the table below, our balance sheet at December 31, 2011 reflects accrued interest on our bank debt of \$0.4 million which was paid in January 2012.

The following summarizes our contractual financial obligations for continuing operations at December 31, 2011 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities.

	Payment due by period (in thousands)							
	2012	2013	2014	2015	2016	Thereafter	Total	
Bank Debt(a)	\$ —	\$ —	\$ —	\$175,000	\$50,000	\$ —	\$225,000	
Operating Leases	497	548	104	44	_		1,193	
Other Loans and Notes Payable	406	138	_	1 <u></u>			544	
Leasing Commitments	1,172	-	_	_		_	1,172	
Derivative Obligations(b)		_	642		_		642	
Firm Commitments(c)	1,164	6,200	6,342	7,051	7,051	42,613	70,421	
Asset Retirement Obligations(d)	600	563	684	531	475	15,817	18,670	
Total Contractual Obligations	\$3,839	<u>\$7,449</u>	<u>\$7,772</u>	\$182,626	\$57,526	\$58,430	\$317,642	

⁽a) Due at termination date of respective facility. Interest paid on our bank credit facilities would be approximately \$8.5 million per year from 2012 through 2015 and \$4.2 million in 2016 assuming no change in the interest rate or outstanding balance.

Interest Rates

At December 31, 2011, we had \$225.0 million of debt outstanding under our senior credit facility and second lien credit agreement. This bears interest at floating rates, which averaged 2.5% and 8.3% on our senior credit facility and second lien credit agreement, respectively, at December 31, 2011. The 30-day London Interbank Offered Rate ("LIBOR") on December 31, 2011 was 0.3%.

Off-Balance Sheet Arrangements

We do not currently use any off-balance sheet arrangements to enhance our liquidity or capital resource position, or for any other purpose.

⁽b) Derivative obligations represent net open derivative contracts valued as of December 31, 2011.

⁽c) Includes sales, gathering and processing agreements.

⁽d) The ultimate settlement and timing cannot be precisely determined in advance.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various risks, including energy commodity price risk. We expect energy prices to remain volatile and unpredictable. If energy prices were to decrease for a substantial amount of time or decline significantly, revenues and cash flows would significantly decline, and our ability to borrow to finance our operations could be adversely impacted. Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of, and demand for, oil and natural gas. Conversely, increases in the market prices for oil and natural gas can have a favorable impact on our financial condition, results of operations and capital resources. Based on December 31, 2011 reserve estimates, we project that a 10% decline in the price per barrel of oil, price per barrel of NGLs and the price per Mcf of gas from average 2011 prices would reduce our gross revenues, before the effects of derivatives, for the year ending December 31, 2012 by approximately \$16.3 million.

We have designed our hedging policy to reduce the risk of price volatility for our production in the natural gas and crude oil markets. Our risk management policy provides for the use of derivative instruments to manage these risks. The types of derivative instruments that we use include swaps, collars, put spreads, put options, swaptions and three-way collars. The volume of derivative instruments that we may use are governed by the risk management policy and can vary from year to year, but under most circumstances will apply to only a portion of our current and anticipated production, and will provide only partial price protection against declines in oil and natural gas prices. We are exposed to market risk on our open contracts, to the extent of changes in market prices of oil and natural gas. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged. Further, if our counterparties should default, this protection might be limited as we might not receive the benefits of the hedges.

Dain Monket

At December 31, 2011, the following commodity derivative contracts were outstanding:

Period	Volume	Put Option	Floor	Ceiling	Swap	Fair Market Value (\$ in Thousands)
Oil						
201 2—Collar	660,000 Bbls	\$ <i>-</i>	\$69.44	\$110.21	\$ —	\$ (2,363)
2013—Collar	300,000 Bbls	_	72.40	116.30		(490)
	960,000 Bbls					\$ (2,853)
Natural Gas						
2012—Swap	2,400,000 Mcf	\$ <i>-</i>	\$ —	\$ —	\$5.04	\$ 3,912
2012—Swaption	600,000 Mcf				5.25	1,047
2012—Collar	3,000,000 Mcf		4.70	5.89	_	4,112
2012—3-Way Collar	2,640,000 Mcf	3.66	4.48	5.13		1,333
2013—Put	2,640,000 Mcf		5.00	_	_	2,730
2013—Swap	2,880,000 Mcf		_	_	4.30	1,377
2013—Collar	3,360,000 Mcf		4.77	5.68		3,465
2013—3-Way Collar	1,920,000 Mcf	3.53	4.38	5.08		861
2014—Call	1,800,000 Mcf	_	_	5.00		(642)
	21,240,000 Mcf					\$18,195

⁽¹⁾ Item 305(a) of Regulation S-K requires that tabular information relating to contract terms allow readers of the table to determine expected cash flows from the market risk sensitive instruments for each of the next five years. At December 31, 2011, we had commodity derivative contracts in place for the next three years, relating to production through 2014.

We are also exposed to market risk related to adverse changes in interest rates. Our interest rate risk exposure results primarily from fluctuations in short-term rates, which are LIBOR and prime rate based, as determined by our lenders, and may result in reductions of earnings or cash flows due to increases in the interest rates we pay on our obligations. We have used, in the past, an interest rate swap agreement to manage risk associated with interest payments on amounts outstanding from variable rate borrowings under our senior credit facility. Under our interest rate swap agreement, we agreed to pay an amount equal to a specified rate of interest times a notional principal amount, and to receive in return, a specified variable rate of interest times the same notional principal amount. This swap expired in November 2010.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REX ENERGY CORPORATION INDEX TO FINANCIAL STATEMENTS

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Report of Independent Registered Public Accounting Firm

The Board of Directors Rex Energy Corporation:

We have audited the accompanying consolidated balance sheet of Rex Energy Corporation and subsidiaries (the Company) as of December 31, 2011 and the related consolidated statements of operations, changes in noncontrolling interests and stockholders' equity (deficit), and cash flows for the year then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2011, and the results of their operations and their cash flows for the year then ended in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with standards of the Public Company Accounting Oversight Board (United States), the Company's internal controls over financial reporting as of December 31, 2011, based on criteria established in *Internal Controls—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 15, 2012 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP Dallas, Texas March 15, 2012

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Rex Energy Corporation State College, Pennsylvania

We have audited the accompanying consolidated balance sheet of Rex Energy Corporation as of December 31, 2010, and the related consolidated statements of operations, owners' equity and noncontrolling interests, and cash flows for each of the years in the two-year period ended December 31, 2010. We have also audited Rex Energy Corporation's internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Rex Energy Corporation's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Rex Energy Corporation as of December 31, 2010, and the consolidated results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, Rex Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

Malin, Bergquist & Company, LLP Pittsburgh, Pennsylvania March 3, 2011

CONSOLIDATED BALANCE SHEETS (\$ in Thousands, Except Share and Per Share Data)

	December 31, 2011	December 31, 2010
ASSETS		
Current Assets	¢ 11.706	¢ 11.000
Cash and Cash Equivalents	\$ 11,796	\$ 11,008 28,849
Accounts Receivable	17,717 10,404	4,564
Assets Held For Sale	24,808	47,884
Inventory, Prepaid Expenses and Other	1,191	1,327
· · · ·		
Total Current Assets Property and Equipment (Successful Efforts Method)	65,916	93,632
Evaluated Oil and Gas Properties	349,938	241,586
Unevaluated Oil and Gas Properties	123,241	64,115
Other Property and Equipment	43,542	42,178
Wells and Facilities in Progress	66,548	17,026
Pipelines	4,408	4,080
Total Property and Equipment	587,677	368,985
Less: Accumulated Depreciation, Depletion and Amortization	(107,433)	(93,062)
Net Property and Equipment	480,244	275,923
Restricted Cash	25	16,111
Deferred Financing Costs and Other Assets—Net	3,380	1,570
Equity Method Investments	41,683	18,399
Long-Term Deferred Tax Asset	1,727	0
Long-Term Derivative Instruments	8,576	1,450
Total Assets	\$ 601,551	\$407,085
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts Payable	\$ 41,558	\$ 46,192
Accrued Expenses	15,682	8,691
Short-Term Derivative Instruments	2,363	1,860
Current Deferred Tax Liability	2,141	1,908
Liabilities Related to Assets Held for Sale	1,622	4,686
Total Current Liabilities	63,366	63,337
Senior Secured Line of Credit and Long-Term Debt	225,138	10,120
Long-Term Derivative Instruments	1,275	1,517
Long-Term Deferred Tax Liability	84	5,930
Other Deposits and Liabilities	744	4,283
Future Abandonment Cost	18,670	17,222
Total Liabilities	309,277	102,409
Commitments and Contingencies (See Note 8)		
Owners' Equity		
Common Stock, \$.001 par value per share, 100,000,000 shares authorized		
and 44,859,220 shares issued and outstanding on December 31, 2011 and		
44,306,677 shares issued and outstanding on December 31, 2010	44	44
Additional Paid-In Capital	376,843	373,856
Accumulated Deficit	(84,888)	(69,519)
Rex Energy Owners' Equity	291,999	304,381
Noncontrolling Interests	275	295
Total Owners' Equity	292,274	304,676
Total Liabilities and Owners' Equity	\$ 601,551	\$407,085

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF OPERATIONS (\$ and Shares in Thousands, Except Share and Per Share Data)

	Year E	oer 31,	
	2011	2010	2009
OPERATING REVENUE			
Oil, Natural Gas and NGL Sales	\$111,879	\$ 67,224	\$ 48,534
Other Revenue	2,727	1,539	157
TOTAL OPERATING REVENUE OPERATING EXPENSES	114,606	68,763	48,691
Production and Lease Operating Expense	33,116	24,656	22,157
General and Administrative Expense	23,636	17,141	15,858
(Gain) Loss on Disposal of Asset	502	(16,395)	427
Impairment Expense	14,631	8,863	1,625
Exploration Expense	2,507	2,578	2,080
Depreciation, Depletion, Amortization and Accretion	28,361	21,806	25,205
Other Operating Expense	2,569	1,341	0
TOTAL OPERATING EXPENSES	105,322	59,990	67,352
INCOME (LOSS) FROM OPERATIONS OTHER INCOME (EXPENSE)	9,284	8,773	(18,661)
Interest Income	10	68	7
Interest Expense	(2,019)	(1,070)	(833)
Gain (Loss) on Derivatives, Net	18,916	6,055	(7,913)
Other Income (Expense)	79	(321)	(161)
Income (Loss) from Equity Method Investments	81	(200)	(9)
TOTAL OTHER INCOME (EXPENSE) INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE INCOME TAX	17,067 26,351	4,532 13,305	(8,909) (27,570)
Income Tax Benefit (Expense)	(8,270)	(5,500)	11,002
INCOME (LOSS) FROM CONTINUING OPERATIONS Income (Loss) From Discontinued Operations, Net of Income Taxes	18,081 (33,457)	7,805 (2,022)	(16,568)
NET INCOME (LOSS)	(15,376)	5,783	(16,245)
Net Loss Attributable to Noncontrolling Interests	(7)	(253)	(12)
NET INCOME (LOSS) ATTRIBUTABLE TO REX ENERGY	<u>\$(15,369)</u>	\$ 6,036	<u>\$(16,233)</u>
Earnings Per Common Share: Basic—income (loss) from continuing operations attributable to Rex common shareholders	\$ 0.41	\$ 0.18	\$ (0.45)
Basic—income (loss) from discontinued operations attributable to Rex common shareholders	(0.76)	(0.05)	0.01
Basic—net income (loss) attributable to Rex common shareholders Basic—weighted average shares of common stock outstanding	\$ (0.35) 43,930	\$ 0.13 43,281	\$ (0.44) 36,806
common shareholders Diluted—income (loss) from discontinued operations attributable to Rex	\$ 0.41	\$ 0.18	\$ (0.45)
common shareholders	(0.76)	(0.05)	0.01
Diluted—net income (loss) attributable to Rex common shareholders Diluted—weighted average shares of common stock outstanding	\$ (0.35) 44,476	\$ 0.13 43,670	\$ (0.44) 36,806

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CHANGES IN NONCONTROLLING INTERESTS AND STOCKHOLDERS' EQUITY (DEFICIT) (in Thousands)

	Common Shares	Stock Par	Additional Paid-In Capital	Accumulated Deficit	Rex Energy Owners' Equity	Noncontrolling Interests	Total Owners' Equity
Balance December 31, 2008	36,590	\$37	\$291,133	\$(59,322)	\$231,848	\$ 0	\$ 31,848
Non-cash compensation expense	0	0	1,239	0	1,239	0	1,239
Capital contributions	0	0	0	0	0	3,355	3,355
Restricted stock, net	228	0	0	0	0	0	0
Net Loss	0	0	0	(16,233)	(16,233)	(12)	(16,245)
Balance December 31, 2009	36,818	37	292,372	(75,555)	216,854	3,343	220,197
Non-cash compensation expense	0	0	965	0	965	0	965
Issuance of 6,900,000 shares of common stock net of issuance costs of							
\$0.3 million	6,900	7	80,192	0	80,199	0	80,199
Capital contributions	0	0	0	0	0	287	287
Restricted stock, net	567	0	0	0	0	0	0
Stock option exercises	22	0	327	0	327	0	327
Deconsolidation of Keystone Midstream Services, LLC	0	0	0	0	0	(3,082)	(3,082)
Net Income (Loss)	0	0	0	6,036	6,036	(253)	5,783
Balance December 31, 2010	44,307	44	373,856	(69,519)	304,381	295	304,676
Non-cash compensation expense	0	0	1,625	0	1,625	0	1,625
Capital contributions (distributions), net	0	0	0	0	0	(13)	(13)
Restricted stock, net	413	0	0	0	0	0	0
Stock option exercises	139	0	1,362	0	1,362	0	1,362
Net Loss	0	0	0	(15,369)	(15,369)	(7)	(15,376)
Balance December 31, 2011	44,859	<u>\$44</u>	\$376,843	<u>\$(84,888)</u>	\$291,999	\$ 275	\$292,274

CONSOLIDATED STATEMENTS OF CASH FLOWS (\$ in Thousands)

	For the Yea	rs Ended De	cember 31,
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income (Loss)	\$ (15,376)	\$ 5,783	\$(16,245)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities			
(Gain) Loss from Equity Method Investments	(81)	200	9
Non-cash Expenses	1,745	1,251	1,897
Depreciation, Depletion, Amortization and Accretion	28,446	21,806	25,205
Deferred Income Tax Expense (Benefit)	(7,339)	3,771	(10,713)
Unrealized (Gain) Loss on Derivatives	(12,704)	(5,960)	17,002
Dry Hole Expense	32,769	3	135
(Gain) Loss on Sale of Assets	502	(16,395)	427
Impairment Expense	27,808	8,863	1,625
Changes in operating assets and liabilities	44.440		(= aa=
Accounts Receivable	11,118	(14,527)	(7,995)
Inventory, Prepaid Expenses and Other Assets	86	(216)	344
Accounts Payable and Accrued Expenses	(1,128)	32,323	8,801
Other Assets and Liabilities	(1,339)	(2,800)	282
NET CASH PROVIDED BY OPERATING ACTIVITIESCASH FLOWS FROM INVESTING ACTIVITIES	64,507	34,102	20,774
Proceeds from Phase I and Phase II Leasing Initiative	3,209	6,352	. 0
Proceeds from Joint Ventures	0	0	3,120
Change in Restricted Cash	16,086	(16,086)	. 0
Equity Method Investments	(23,204)	(14,018)	(309)
Proceeds from the Sale of Oil and Gas Properties, Prospects and Other Assets	2,729	79,229	17,998
Acquisitions of Undeveloped Acreage	(78,569)	(72,385)	(17,898)
Capital Expenditures for Development of Oil & Gas Properties and Equipment	(196,825)	(78,013)	(32,972)
NET CASH USED IN INVESTING ACTIVITIES CASH FLOWS FROM FINANCING ACTIVITIES	(276,574)	(94,921)	(30,061)
Proceeds from Long-Term Debt and Lines of Credit	240,000	85,000	27,000
Repayments of Long-Term Debt and Lines of Credit	(25,000)	(98,000)	(19,000)
Repayments of Loans and Other Notes Payable	(879)	(753)	(177)
Debt Issuance Costs	(2,615)	(701)	0
Proceeds from the Issuance of Common Stock, Net of Issuance Costs	0	80,192	0
Proceeds from the Exercise of Stock Options	1,362	220	0
Consolidated Joint Ventures	(20)	0	0
Consolidated Joint Ventures	7	287	0
NET CASH PROVIDED BY FINANCING ACTIVITIES	212,855	66,245	7,823
NET INCREASE (DECREASE) IN CASH	788	5,426	(1,464)
CASH—BEGINNING	11,008	5,582	7,046
CASH—ENDING	\$ 11,796	<u>\$ 11,008</u>	\$ 5,582
SUPPLEMENTAL DISCLOSURES			
Interest Paid	1,549	846	581
Taxes Paid	312	299	0
Equipment Financing	474	1,336	542
Equipment Contributed by Consolidated Joint Ventures	0	0	3,355

See accompanying notes to the consolidated financial statements

REX ENERGY CORPORATION NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION AND PRINCIPLES OF CONSOLIDATION

Rex Energy Corporation, together with our subsidiaries (the "Company"), is an independent oil and gas company operating in the Appalachian Basin and the Illinois Basin. In the Appalachian Basin, we are focused on our Marcellus Shale drilling projects and Utica Shale and Upper Devonian Shale exploration activities. In the Illinois Basin, in addition to our developmental oil drilling, we are focused on the implementation of enhanced oil recovery on our properties. We pursue a balanced growth strategy of pursuing our higher potential exploration drilling prospects and actively seeking to acquire complementary oil and natural gas properties.

The accompanying Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of all of our wholly owned subsidiaries. All material intercompany balances and transactions have been eliminated. Unless otherwise indicated, all references to "Rex Energy Corporation," "our," "we," "us" and similar terms refer to Rex Energy Corporation and its subsidiaries together. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies.

Certain prior year amounts have been reclassified to conform to the report classifications for the year ended December 31, 2011, with no effect on previously reported net income, net income per share, accumulated deficit or stockholders' equity. All prior year amounts that have been reclassified are immaterial.

We consolidate all of our subsidiaries in the accompanying Consolidated Balance Sheets as of December 31, 2011 and 2010 and the Consolidated Statements of Operations, Cash Flows and Changes in Noncontrolling Interests and Stockholders' Equity (Deficit) of the years ended December 31, 2011, 2010 and 2009. Investments in unconsolidated affiliates in which we are able to exercise significant influence are accounted for using the equity method. All intercompany transactions and accounts have been eliminated.

Discontinued Operations

During December 2011, our board of directors approved a formal plan to sell our DJ Basin assets located in the states of Wyoming and Colorado. In March 2009, we completed the sale of certain oil and gas leases, wells and related assets predominantly located in the Permian Basin in the states of Texas and New Mexico. Pursuant to the rules for discontinued operations, these assets have been classified as Assets Held for Sale on our Consolidated Balance Sheets and the results of operations are reflected as Discontinued Operations in our Consolidated Statements of Operations. Unless otherwise noted, all disclosures and tables reflect the results of continuing operations and exclude any assets, liabilities or results from our discontinued operations. For additional information see Note 4, *Discontinued Operations/Assets Held for Sale*, to our Consolidated Financial Statements.

Subsidiary Guarantors

We filed a registration statement on Form S-3, which became effective June 15, 2011, with respect to certain securities described therein, including debt securities, which may be guaranteed by certain of our subsidiaries. Rex Energy Corporation is a holding company with no independent assets or operations. We contemplate that if guaranteed debt securities are offered pursuant to the registration statement, all guarantees will be full and unconditional and joint and several and any subsidiaries other than the subsidiary guarantors will be minor. In addition, there are no significant restrictions on the ability of Rex Energy Corporation to receive funds from our subsidiaries through dividends, loans, advances or otherwise.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the periods reported. Actual results could differ from these estimates.

Significant estimates made in preparing these Consolidated Financial Statements include, among other things, estimates of the proved oil and natural gas reserve volumes used in calculating Depletion, Depreciation and Amortization ("DD&A") expense; the estimated future cash flows and fair value of properties used in determining the need for any impairment write-down; fair values of financial derivative instruments; volumes and prices for revenues accrued; estimates of the fair value of equity-based compensation awards; deferred tax valuation allowance and the timing and amount of future abandonment costs used in calculating asset retirement obligations. Future changes in the assumptions used could have a significant impact on reported results in future periods. The significant estimates are based on current assumptions that may be materially affected by changes to future economic conditions such as the market prices received for sales of volumes of oil and natural gas, interest rates and our ability to generate future income.

Cash and Cash Equivalents

We consider all highly liquid investments with original maturity of three months or less when purchased to be cash equivalents. As of December 31, 2010, we had approximately \$16.1 million accounted for as Restricted Cash on our Consolidated Balance Sheet. The amounts as of December 31, 2010, are primarily related to funds prepaid to us from Sumitomo for the purpose of acquiring mineral leases in Butler County, Pennsylvania, described as Phase I leases in Note 3, *Business and Oil and Gas Property Acquisitions and Dispositions*, to our Consolidated Financial Statements.

Accounts Receivable

Our trade accounts receivable, which are primarily from oil and natural gas sales and joint interest billings, are recorded at the invoiced amount and include production receivables. The production receivable is valued at the invoiced amount and does not bear interest. Accounts receivable also include joint interest billing receivables which represent billings to the non-operators associated with the drilling and operation of wells and are based on those owners' working interests in the wells. We have assessed the financial strength of our customers and joint owners and recorded bad debts as necessary.

We use the allowance method to account for uncollectible accounts receivable. A reserve is recorded for amounts we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted.

To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those properties are estimated and recorded as Accounts Receivable in the accompanying Consolidated Balance Sheets.

At December 31, 2011, we carried approximately \$13.6 million in production receivable, of which approximately \$12.9 million were production receivables due from three purchasers. At December 31, 2010, we carried approximately \$8.1 million in production receivable, of which approximately \$7.3 million were production receivables due from three purchasers. In addition, we carried approximately \$3.0 million in receivables from Sumitomo Corporation at December 31, 2011 and \$19.2 million at December 31, 2010 (see Note 3, Business and Oil and Gas Property Acquisition Dispositions, to our Consolidated Financial Statements) that was in relation to our joint operations.

Inventory

Inventory is valued at the lower of cost or market value and consists of our ownership interest in oil and NGLs held in terminal tanks located in the field. Oil and NGL cost basis is calculated using the average cost method, with average cost defined as production and lease operating expenses net of DD&A. General and Administrative expenses are not allocated to the cost of inventory for the purpose of valuing inventory.

Oil and Natural Gas Property, Depreciation and Depletion

We account for natural gas and oil exploration and production activities under the successful efforts method of accounting. Proved developed natural gas and oil property acquisition costs are capitalized when incurred. Unproved properties with individually significant acquisition costs are assessed periodically on a property-by-property basis, and any impairment in value is recognized. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved natural gas and oil properties. Natural gas and oil exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether they have discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. Costs to develop estimated proved reserves, including the costs of all development well and related equipment used in the production of natural gas and oil, are capitalized.

Depletion is calculated using the unit-of-production method. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. We periodically review estimated proved reserve estimates and make changes as needed to depletion expenses to account for new wells drilled, acquisitions, divestitures and other events which may have caused significant changes in our estimated proved reserves. The costs of unproved properties are withheld from the depletion base until such time as they are proved. When estimated proved reserves are assigned, the cost of the property is added to costs subject to depletion calculations. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is allocated to the associated producing properties as the undeveloped acreage is developed. Individually significant non-producing properties are periodically assessed for impairment of value. Service properties, equipment and other assets are depreciated using the straight-line method over their estimated useful lives of three to 40 years.

When circumstances indicate that an asset may be impaired, we compare expected undiscounted future cash flows at a producing field to the unamortized capitalized cost of the asset. If the future undiscounted cash flows, based on our estimate of future natural gas and oil prices, operating costs, anticipated production from estimated proved reserves and other relevant data, are lower than the unamortized capitalized cost, the capitalized cost is reduced to fair value. Fair value is calculated by discounting the future cash flows at an appropriate risk-adjusted discount rate. When evaluating our unproved oil and gas properties, we utilize active market prices for similar acreage to use as a comparison tool against the carrying value of our properties. If the active market prices for similar acreage do not support our carrying values we then utilize estimates of future value that will be created from the future development of these properties. If future estimated fair value of these properties is lower than the capitalized cost, the capitalized cost is reduced to the estimated future fair value. We recognized approximately \$14.6 million, \$8.9 million and \$1.6 million of impairment from continuing operations on certain oil and gas properties for the years ending December 31, 2011, 2010 and 2009, respectively. We recorded these charges as Impairment Expense on our Consolidated Statements of Operations. For additional information, see Note 17, *Impairment Expense*, to our Consolidated Financial Statements.

Expenditures for repairs and maintenance to sustain production from the existing producing reservoir are charged to expense as incurred. Expenditures to recomplete a current well in a different unproved reservoir are capitalized pending determination that economic reserves have been added. If the recompletion is not successful, the expenditures are charged to expense.

Significant tangible equipment added or replaced that extends the useful or productive life of the property is capitalized. Exper litures to construct facilities or increase the productive capacity from existing reservoirs are capitalized.

Upon the sale or retirement of a proved natural gas or oil property, or an entire interest in unproved leaseholds, the cost and related accumulated DD&A are removed from the property accounts and the resulting gain or loss is recognized. For sales of a partial interest in unproved leaseholds for cash or cash equivalents, sales proceeds are first applied as a reduction of the original cost of the entire interest in the property and any remaining proceeds are recognized as a gain.

Natural Gas and Oil Reserve Quantities

Our estimate of estimated proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. For the years ended December 31, 2011 and 2010, Netherland Sewell and Associates, Inc. ("NSAI") prepared a consolidated reserve and economic evaluation of our proved oil and gas reserves. The preparation of our proved reserve estimates are completed in accordance with our internal control procedures, which include the verification of input data used by NSAI, as well as intense management review and approval.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. Estimates of our crude oil and natural gas reserves, and the projected cash flows derived from these reserve estimates, are prepared by our engineers in accordance with guidelines established by the SEC, including the rule revisions designed to modernize the oil and gas company reserves reporting requirements and which we adopted effective December 31, 2009. The independent reserve engineer estimates reserves annually on December 31. This annual estimate results in a new depletion rate, which we use for the preceding fourth quarter after adjusting for fourth quarter production.

Deferred Financing Costs and Other Assets—Net

At December 31, 2011, we had intangible assets from continuing operations consisting of \$3.3 million, which is primarily made up of loan costs that are amortized using the straight line method over their respective estimated lives, which is, on average, three to five years. We amortize any costs incurred to renew or extend the terms of existing intangible assets over the contract term or estimated useful life, as applicable, using the straight-line method. For the years ended December 31, 2011, 2010, and 2009, we recorded amortization expense from continuing operations of \$0.8 million, \$0.5 million and \$0.4 million, respectively. The aggregate estimated annual amortization expense from continuing operations for each of the next five calendar years is as follows: 2012—\$1.2 million; 2013—\$0.8 million; 2014—\$0.7 million; 2015—\$0.5; and 2016—\$0.1.

The following is a summary of intangible assets at the dates indicated:

	December 31, 2011 (in thousands)	December 31, 2010 (in thousands)
Intangible—Gross	\$ 5,637	\$ 2,920
Accumulated Amortization	(2,329)	(1,526)
Intangible Assets—Net	\$ 3,308	<u>\$ 1,394</u>

Specific to our loan costs, we have incurred gross debt issuance costs of approximately \$4.1 million, \$1.4 million and \$0.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, which are presented net of accumulated amortization of \$1.1 million, \$0.6 million and \$0.4 million, respectively. All intangible assets, including loan costs, at December 31, 2011 are included in Deferred Financing Costs and Other Assets—Net on the Consolidated Balance Sheets.

Future Abandonment Cost

Future abandonment costs are recognized as obligations associated with the retirement of tangible long-lived assets that result from the acquisition and development of the asset. We recognize the fair value of a liability for a retirement obligation in the period in which the liability is incurred. For natural gas and oil properties, this is the period in which the natural gas or oil well is acquired or drilled. The future abandonment cost is capitalized as part of the carrying amount of our natural gas and oil properties at its discounted fair value. The liability is then accreted each period until the liability is settled or the natural gas or oil well is sold, at which time the liability is reversed. If the fair value of a recorded asset retirement obligation changes, a revision is recorded to both the asset retirement obligation and the asset retirement cost.

Accretion expense from continuing operations during the years ended December 31, 2011, 2010 and 2009 totaled approximately \$1.5 million, \$1.7 million and \$1.5 million, respectively. These amounts are recorded as DD&A on our Consolidated Statements of Operations. We account for asset retirement obligations that relate to wells that are drilled jointly based on our interest in those wells.

December 31, 2011 (\$ in Thousands)	December 31, 2010 (\$ in Thousands)
\$17,222	\$16,143
235	196
(266)	(796)
0	(25)
1,479	1,704
<u>\$18,670</u>	\$17,222
	2011 (\$ in Thousands) \$17,222 235 (266) 0 1,479

Revenue Recognition

Oil and natural gas revenue is recognized when the oil or natural gas is delivered to or collected by the respective purchaser, a sales agreement exists, collection for amounts billed is reasonably assured and the sales price is fixed or determinable. Title to the produced quantities transfers to the purchaser at the time the purchaser collects or receives the quantities. In the case of oil and NGL sales, title is transferred to the purchaser when the oil or NGLs leaves our stock tanks and enters the purchaser's trucks. In the case of gas production, title is transferred when the gas passes through the meter of the purchaser. It is the measurement of the purchaser that determines the amount of oil or gas purchased. Prices for such production are defined in sales contracts and are readily determinable based on certain publicly available indices. The purchasers of such production have historically made payment for oil and natural gas purchases within 30-60 days of the end of each production month. We periodically review the difference between the dates of production and the dates we collect payment for such production to ensure that receivables from those purchasers are collectible. The point of sale for our oil, NGL and natural gas production is at its applicable field gathering system. We do not currently participate in any gas-balancing arrangements. We do not recognize revenue for oil and NGL production held in stock tanks before delivery to the purchaser.

To the extent actual quantities and values of oil and natural gas are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and price for those properties are estimated and recorded as Accounts Receivable in the Consolidated Balance Sheets and Oil, Natural Gas and NGL Sales on the Statements of Operations.

Derivative Instruments

We use put and call options (collars), fixed rate swap contracts, swaptions, puts and put spreads to manage price risks in connection with the sale of oil and natural gas. We have also, in the past, used interest rate swap

agreements to manage interest rate risks associated with our variable rate credit facility. We have established the fair value of all derivative instruments using estimates determined by our counterparties and other third-parties. These values are based upon, among other things, future prices, volatility, time to maturity and credit risk. The values we report in our Consolidated Financial Statements change as these estimates are revised to reflect actual results, changes in market conditions or other factors.

We report our derivative instruments at fair value and include them in the Consolidated Balance Sheets as assets or liabilities. The accounting for changes in fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. For derivative instruments designated for hedge accounting, changes in fair value, to the extent the hedge is effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. Any changes in fair value resulting from ineffectiveness are recognized immediately in earnings. During 2009, 2010 and 2011 we did not have any derivative instruments designated for hedge accounting.

For derivative instruments designated as fair value hedges, changes in fair value, as well as the offsetting changes in the estimated fair value of the hedged item attributable to the hedged risk, are recognized currently in earnings. Derivative effectiveness is measured annually based on the relative changes in fair value between the derivative contract and the hedged item over time. For derivatives on oil and natural gas production activity, our evaluations are not documented, and as a result, we record changes on the derivative valuations through earnings. For additional information on our derivative instruments, see Note 11, Fair Value of Financial Instruments and Derivative Instruments, to our Consolidated Financial Statements.

Income Taxes

We are subject to income and other taxes in all areas in which we operate. When recording income tax expense, certain estimates are required because income tax returns are generally filed several months after the close of a calendar year, tax returns are subject to audit which can take years to complete, and future events often impact the timing of when income tax expenses and benefits are recognized. We have deferred tax assets relating to tax operating loss carryforwards and other deductible differences and deferred tax liabilities that relate to other temporary differences.

Deferred tax assets and liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted tax rate. Net deferred tax assets are required to be reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the net deferred tax asset will not be realized.

This process requires our management to make assessments regarding the timing and probability of the ultimate tax impact. We record valuation allowances on deferred tax assets if we determine it is more likely than not that the asset will not be realized. Actual income taxes could vary from these estimates due to future changes in income tax law, significant changes in the jurisdictions in which we operate, our inability to generate sufficient future taxable income, or unpredicted results from the final determination of each year's liability by taxing authorities. These changes could have a significant impact on our financial position.

The accounting estimate related to the tax valuation allowance requires us to make assumptions regarding the timing of future events, including the probability of expected future taxable income and available tax planning opportunities. These assumptions require significant judgment because actual performance has fluctuated in the past and may do so in the future. The impact that changes in actual performance versus these estimates could have on the realization of tax benefits as reported in our results of operations could be material. We continuously evaluate facts and circumstances representing positive and negative evidence in the determination of our ability to realize the deferred tax assets.

We recognize a tax position if it is more likely than not that it will be sustained upon examination. If we determine it is more likely than not a tax position will be sustained based on its technical merits, we record the

impact of the position in our Consolidated Financial Statements at the largest amount that is greater than fifty percent likely of being realized upon ultimate settlement. These estimates are updated at each reporting date based on the facts, circumstances and information available. We are also required to assess at each reporting date whether it is reasonably possible that any significant increases or decreases to the unrecognized tax benefits will occur during the next twelve months (for additional information, see Note 12, *Income Taxes*, to our Consolidated Financial Statements). Our policy is to recognize interest and penalties on any unrecognized tax benefits in interest expense and general and administrative expense, respectively.

Stock-based Compensation

We recognize in the Consolidated Financial Statements the cost of employee and non-employee director services received in exchange for awards of equity instruments based on the grant date fair value of those awards. We use a standard option pricing model (i.e. Black-Scholes) to measure the fair value of employee stock options and stock appreciation rights. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of the grant.

The benefits associated with the tax deductions in excess of recognized compensation cost are reported as a financing cash flow when realized. We recognize compensation costs related to awards with graded vesting on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award were, in-substance, multiple awards (for additional information, see Note 16, *Employee Benefit Plans and Equity Plans*, to our Consolidated Financial Statements). Stock appreciation rights are classified as a liability and are re-measured at fair value each reporting period.

Earnings per Share

Earnings per common share are computed by dividing consolidated net income attributable to us by the weighted average number of common shares outstanding. Diluted earnings per common share are computed by dividing consolidated net income attributable to us by the weighted average number of common shares outstanding during the period, including any potentially dilutive outstanding securities, such as options and warrants. The potentially dilutive outstanding securities are calculated using the treasury stock method. At December 31, 2011, we had 44,859,220 common shares outstanding, 698,327 options outstanding and 20,500 stock appreciation rights outstanding with no outstanding warrants or other potentially dilutive securities. For additional information, see Note 13, *Earnings per Common Share*, to our Consolidated Financial Statements.

Capital Leases

As a lessee, we determine if a lease is a capital lease if it meets one of four of the following criteria:

- The ownership of the leased property transfers to us by the end of the lease term, or shortly thereafter, in exchange for the payment of a nominal fee.
- The lease contains a bargain purchase option.
- The lease term is equal to 75% or more of the estimated economic life of the leased property.
- The present value at the beginning of the lease term of the minimum lease payments, excluding that portion of the payments representing executor costs such as insurance, maintenance, and taxes to be paid by the lessor, including any profit thereon, equals or exceeds 90% of the excess of the fair value of the leased property to the lessor at the lease inception over any related investment tax credit retained by the lessor and expected to be realized by the lessor.

As of December 31, 2011 we had capital leases on field vehicles being used in our Illinois and Appalachian Basin operations. We recorded these leases as Other Property and Equipment on our Consolidated

Balance Sheets in the amount of \$2.3 million as of December 31, 2011, and \$1.8 million as of December 31, 2010. The remaining obligation to be paid on these leases totaled approximately \$0.5 million, of which \$0.1 was classified as Senior Secured Line of Credit and Long-Term Debt under Long-Term Liabilities and \$0.4 was classified as Accounts Payable under Current Liabilities on our Consolidated Balance Sheets, all of which is expected to be paid by 2015. We recorded approximately \$0.4 million, \$0.2 million and \$48,000 of amortization on these vehicles, classified as DD&A on our Consolidated Statements of Operations, for the years ended December 31, 2011, 2010 and 2009, respectively.

Recent Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") 2011-11, *Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities*. ASU 2011-11 provides new disclosure requirements related to offsetting arrangements to allow investors to better compare financial statements prepared in accordance with IFRS and U.S. GAAP. The amendment requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. An entity is required to apply the amendments for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods, including retrospective application for all comparative periods presented. Although we currently are not engaged in any arrangements that would be effected by these disclosure requirements, we believe that ASU 2011-11 may have a material impact on future disclosures pending our entrance into an offsetting arrangement.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS. ASU 2011-04 generally provides a uniform framework for fair value measurements and related disclosures between GAAP and International Financial Reporting Standards ("IFRS"). Additional disclosure requirements in the update include: (1) for Level 3 fair value measurements, quantitative information about unobservable inputs used, a description of the valuation process used by the entity, and a qualitative discussion about the sensitivity of the measurements to changes in the unobservable inputs; (2) for an entity's use of a nonfinancial asset that is different from the asset's highest and best use, the reason for the difference; (3) for financial instruments not measured at fair value but for which disclosure of fair value is required, the fair value hierarchy level in which the fair value measurements were determined; and (4) the disclosures of all transfers between Level 1 and Level 2 of the fair value hierarchy. This update is effective for annual and interim periods beginning on or after December 31, 2011. We adopted ASU 2011-04 on January 1, 2012, with no material impact.

In December 2010, the FASB issued ASU 2010-29, *Disclosure of Supplementary Pro Forma Information for Business Combinations* ("ASU 2010-29"). The amendments to the codification clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Additionally, the supplemental pro forma disclosures under Topic 805 have been expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The amendments in ASU 2010-29 are effective prospectively for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. Although we have not entered into any significant business combinations in our recent history, we believe that ASU 2010-29 may have a material impact on future disclosures depending on the size and nature of any future business combinations that we may enter into. We adopted ASU 2010-29 on January 1, 2011.

3. BUSINESS AND OIL AND GAS PROPERTY ACQUISITIONS AND DISPOSITIONS

Acquisitions

We have made no significant acquisitions for the years ended December 31, 2011, 2010 and 2009.

Dispositions

Sumitomo Joint Venture

On September 30, 2010, we entered into a joint venture transaction with Sumitomo Corporation ("Sumitomo"). In Butler County, Pennsylvania we sold a 15% non-operated interest in approximately 40,700 net acres for approximately \$30.6 million in cash at closing and \$30.6 million in the form of a drilling carry of 80% of our drilling and completion costs in the area. Pursuant to the Participation and Exploration Agreement (the "Sumitomo PEA"), Sumitomo agreed to pay all of the costs to lease approximately 9,000 net acres in the Butler County Area of Mutual Interest ("AMI") (the "Phase I Leasing"), and to pay to us a leasing management fee of \$1,000 per net acre during the Phase I Leasing. The Phase I Leasing and drilling carry for Butler County were completed during the first quarter of 2011, resulting in final ownership percentages of 70% to us and 30% to Sumitomo. The cost of future leasing activities will be shared on a 70/30 basis, with Sumitomo paying to us a management fee of \$150 per net acre acquired. In addition to the sale of undeveloped acreage, we also sold to Sumitomo 30% of our interests in 20 Marcellus Shale wells within the Butler County area and 30% of our interest in Keystone Midstream Services, LLC ("Keystone Midstream") (for additional information on Keystone Midstream, see Note 5, *Variable Interest Entities*, and Note 6, *Equity Method Investments*, to our Consolidated Financial Statements).

In our Marcellus Shale joint venture project areas with WPX Energy San Juan, LLC (formerly known as Williams Production Company, LLC) and Williams Production Appalachia, LLC (collectively, "Williams"), which is discussed below, we sold to Sumitomo 20% of our interests in 23,500 net acres for approximately \$19.0 million in cash at closing and \$19.0 million in the form of a drilling carry of 80% of our drilling and completion costs in the areas. In addition, we sold 20% of our interests in 19 Marcellus Shale wells located in the Williams joint venture areas and 20% of our interest in RW Gathering, LLC ("RW Gathering") (for additional information on RW Gathering, see Note 6, *Equity Method Investments*, to our Consolidated Financial Statements).

In addition to the areas above, we sold to Sumitomo 50% of our interests in approximately 4,500 net acres in Fayette and Centre Counties, Pennsylvania for \$9.2 million in cash at closing and \$9.2 million in the form of a drilling carry of 80% of our drilling and completion costs. Pursuant to the Sumitomo PEA, the drilling carry for these areas was to be applied, at our discretion, to drilling and completion costs attributable to either the Butler County or Williams joint venture areas. As of December 31, 2011, there was no remaining drilling carries with Sumitomo.

At closing, we received approximately \$99.5 million in cash, which included a reimbursement for leasing expenses incurred subsequent to the effective date of September 1, 2010, in the amount of approximately \$7.6 million. Additionally, the cash payment included a reimbursement for drilling related expenses incurred subsequent to the effective date in the amount of approximately \$7.5 million, which was applied against the drilling carry. Pursuant to industry rules, we do not make any accounting for the carried amounts paid on our behalf by Sumitomo. We recognized approximately a \$16.5 million gain on the Sumitomo transaction which is classified as (Gain) Loss on Disposal of Asset on our Consolidated Statement of Operations.

Williams Joint Venture

In the second quarter of 2009, we entered into a Participation and Exploration Agreement (the "Williams PEA") with Williams that was effective as of May 5, 2009. Under the terms and conditions of the Williams PEA, Williams acquired, through a "drill-to-earn" structure, a 50% working interest in certain oil and gas leases covering approximately 43,672 net acres in Centre, Clearfield and Westmoreland Counties, Pennsylvania (the "Project Area"). The Williams PEA effectively provided that, for Williams to earn its 50% interest in the Project Area, Williams would bear 90% of all costs and expenses incurred in the drilling and completion of all wells jointly drilled in the Project Area until such time as Williams had invested approximately \$74.0 million (approximately \$33.0 million on behalf of us and \$41.0 million for Williams' 50% share of the wells). The Williams PEA represents a pooling of assets in a joint undertaking by us and Williams and, therefore, we do not

make any accounting for the \$33.0 million of carried interest paid on our behalf by Williams. As of December 31, 2010, Williams had completed its carry obligation and acquired a 50% working interest in the leases within the Project Area, and the parties will share all costs of the joint venture operations within an area of mutual interest (including the Project Area) in accordance with their participating interests, which are expected to be on a 50 (Williams)/40 (Rex)/10 (Sumitomo) basis.

In accordance with the terms of the Williams PEA, Williams reimbursed us for approximately \$3.1 million for Williams' share of certain expenses incurred in the acquisition and development of oil and gas leases within the Project Area that we had previously paid. Williams became the operator of the Project Area on January 1, 2010.

Other

In the first quarter of 2009, we completed the sale of certain oil and gas leases, wells and related assets located primarily in the Permian Basin in the states of Texas and New Mexico for net proceeds of approximately \$17.3 million and recorded a loss of \$0.4 million. We have reflected the results of these divested operations as discontinued operations rather than a component of continuing operations. For additional information, see Note 4, *Discontinued Operations/Assets Held for Sale*, to our Consolidated Financial Statements.

4. DISCONTINUED OPERATIONS/ASSETS HELD FOR SALE

During December 2011, our board of directors approved a formal plan to sell our DJ Basin assets located in the states of Wyoming and Colorado, and we have engaged an advisor to assist with the marketing efforts. The assets are available for immediate sale pending normal due diligence incurred during the course of business, with a sale expected within one year. The recording of Depreciation, Depletion, Amortization and Accretion ("DD&A") expense related to our DJ Basin assets ceased in December 2011. We evaluated the value, less cost to sell, of our DJ Basin assets, as of December 31, 2011, and determined that the fair value of our assets was greater than the carrying amount of the assets. Therefore no adjustment to the carrying value was required. Upon the completion of a sale, we will have no continuing activities in the DJ Basin or continuing cash flows from this region.

These assets have been classified as Assets Held for Sale on our Balance Sheet as of December 31, 2011 and December 31, 2010, and the results of operations are reflected in Discontinued Operations in our Consolidated Statements of Operations. We incurred direct wage costs in the amount of \$0.2 million associated with the sale of our DJ Basin assets, which was recorded in Discontinued Operations on our Consolidated Statement of Operations. We have included \$24.8 million and \$47.9 million of net assets located in the DJ Basin as Assets Held for Sale on our Consolidated Balance Sheets as of December 31, 2011 and 2010, respectively. We have included approximately \$1.6 and \$4.7 million of liabilities as Liabilities Related to Assets Held for Sale on our Consolidated Balance Sheets as of December 31, 2011 and 2010, respectively. These liabilities primarily relate to Accounts Payable and Accrued Expenses.

On March 24, 2009, we completed the sale of certain oil and gas leases, wells and related assets predominantly located in the Permian Basin in the states of Texas and New Mexico. We received net cash proceeds of approximately \$17.3 million, which was able to be adjusted by certain post-closing adjustments, plus the assumption of certain liabilities, based on an effective date of October 1, 2008. Upon closing of the sale, we used the proceeds to pay down our long-term borrowings on our Senior Credit Facility.

Pursuant to the accounting rules for discontinued operations, these assets were classified as Assets Held for Sale on our Balance Sheet as of December 31, 2009, and results of operations are reflected in Discontinued Operations in our Consolidated Statements of Operations. We recorded a loss on sale of assets of approximately \$0.4 million in our Consolidated Statement of Operations. Upon closing of the sale, we recorded severance wages in Discontinued Operations of approximately \$0.2 million for our former employees in the Southwest Region.

Summarized financial information for Discontinued Operations is set forth in the table below, and does not reflect the costs of certain services provided. Such costs, which were not allocated to the Discontinued Operations, were for services, including legal counsel, insurance, external audit fees, payroll processing, certain human resource services and information technology systems support. As of December 31, 2011 and 2010, we did not have any assets or liabilities classified as held for sale related to the Permian Basin.

	December 31, (\$ in thousands)		
	2011	2010	2009
Revenues:			
Oil and Gas Sales	\$ 556	\$ 0	\$ 193
Total Operating Revenue	556	0	193
Costs and Expenses:			
Production and Lease Operating Expense	493	0	237
General and Administrative Expense	1,745	782	(97)
Exploration Expense	33,812	2,664	0
Impairment Expense	13,177	0	0
Depreciation, Depletion, Amortization and Accretion	85	1	0
Other Operating Expense	1	0	0
Gain from Derivatives, net	0	0	(558)
Interest Expense	1	0	0
Other Expense	1	0	0
Total Costs and Expenses	49,315	3,447	(418)
Income (Loss) from Discontinued Operations Before Income Taxes	(48,759)	(3,447)	611
Income Tax (Expense) Benefit	15,302	1,425	(288)
Income (Loss) from Discontinued Operations, net of taxes	\$(33,457)	\$(2,022)	\$ 323
Production:			
Crude Oil (Bbls)	6,939	0	7,507
Natural Gas (Mcf)	0	0	61,661
Total (Mcfe)	41,634	0	106,703

5. CONSOLIDATED SUBSIDIARIES

Water Solutions Holdings

In November 2009, we entered into a limited liability agreement with Sand Hills Management, LLC ("Sand Hills") to form Water Solutions Holdings, LLC ("Water Solutions") for the purpose of acquiring, managing and operating water treatment, disposal and transportation facilities that are designed to treat, dispose or transport brine and fresh waters used and produced in oil and gas well development activities. The members of Water Solutions are Rex Energy Corporation, which owns an 80% membership interest, and Sand Hills, which owns a 20% membership interest and serves as the operator of the entity.

We fully consolidated the accounts of Water Solutions in our financial statements and accounted for the 20% equity interest owned by Sand Hills as a noncontrolling interest. As of December 31, 2011 and 2010, has recourse to our general credit. Water Solutions is financed through cash contributions from its members. We contributed approximately \$20,000 in cash in 2011 and approximately \$1.1 million in cash in 2010 to fund the operations of Water Solutions.

NorthStar #3, LLC

In August 2011, our wholly owned subsidiary, R.E. Gas Development, LLC ("R.E. Gas") and NorthStar Water Management ("NorthStar") formed NorthStar #3, LLC ("NorthStar #3") to construct, own and operate a water disposal well in Mahoning County, Ohio. At December 31, 2011, R.E. Gas owned a 51% membership interest in NorthStar #3 and the remaining 49% membership interest was owned by NorthStar, which also serves as the operator of the entity. To supplement the operations of NorthStar #3, the entity entered into a promissory note with us. As of December 31, 2011, the amount owed to us under the promissory note was \$4.9 million (for additional information see Note 9, *Related Party Transactions*, to our Consolidated Financial Statements).

A variable interest entity ("VIE") is an entity that by design has insufficient equity to permit it to finance its activities without additional subordinated financial support or equity holders that lack the characteristics of a controlling financial interest. Based on these factors we have determined NorthStar #3 to be a VIE.

We are considered the primary beneficiary of the entity and have consolidated the financial results. To be considered the primary beneficiary, a member must have the power to direct the activities that most significantly impact the entity's performance and have a significant variable interest that carries with it the obligation to absorb the losses or the right to receive benefits. The activities that most significantly impact the entity's economic performance relate to the drilling of a successful disposal well with ample capacity and the ongoing operation of the well. Per the membership agreement, we hold a first right of refusal on all capacity rights for the disposal well, giving us the ability to make decisions regarding the operation and capacity of the well based on market conditions and, thus, the ability to direct the activities that most significantly impact the economic performance of the entity. We hold a significant variable interest in the entity in the form of our 51% membership interest and the \$4.9 million promissory note. We have no recourse to recover the amount of the promissory note in the event that the disposal well is unsuccessful, leaving us with the obligation to absorb the losses. Upon success of the disposal well, we will initially have the right to approximately 87.3% of the available cash at the end of the period which covers the repayment of the note and our membership interest.

As of December 31, 2011, we contributed \$490 in capital to NorthStar #3. The carrying amount and classifications of NorthStar #3 assets and liabilities as of December 31, 2011 are as follows, with no restrictions or obligations to use certain assets to settle associated liabilities (NorthStar #3 did not exist as of December 31, 2010):

	December 31, 2011 (in thousands)
ASSETS	
Cash and Cash Equivalents	\$ 10
Wells and Facilities in Progress	5,059
Total Assets	\$5,069
LIABILITIES	
Accounts Payable	\$ 134
Note Payable	4,935
Total Liabilities	\$5,069

6. EQUITY METHOD INVESTMENTS

RW Gathering

Pursuant to the terms of the Williams PEA, we and Williams agreed to form RW Gathering, LLC ("RW Gathering"), a Delaware limited liability company, to own any gas-gathering assets which we agreed to jointly construct in order to facilitate the development of our Project Area. The initial members of RW Gathering were Williams and us, each owning an equal interest in the company. On September 30, 2010, pursuant to the Sumitomo PEA, we sold 20% of our interest in RW Gathering to Sumitomo, decreasing our ownership in RW Gathering to 40% (for additional information, see Note 3, *Business and Oil and Gas Property Acquisitions and Dispositions*, to our Consolidated Financial Statements). As of January 1, 2010, Williams became the manager of RW Gathering.

We recorded our investment in RW Gathering of approximately \$15.7 million and \$6.4 million as of December 31, 2011 and 2010, respectively, on our Consolidated Balance Sheets as Equity Method Investments. During 2011, we contributed approximately \$9.7 million in cash to RW Gathering to support current pipeline and gathering line construction, compared to \$5.6 million during the same period in 2010. RW Gathering recorded net losses from continuing operations of \$0.4 million and \$0.1 million for the years ended December 31, 2011 and 2010, respectively. The losses incurred were due to insurance fees, bank fees, rent expenses and DD&A expense. Our share of the net loss from continuing operations is recorded on the Statements of Operations as Loss on Equity Method Investments.

When evaluating our Equity Method Investments for impairment we review our ability to recover the carrying amount of such investments or the entity's ability to sustain earnings that justify its carrying amount. In the case of RW Gathering, the nature of its assets is such that under normal circumstances an entity would capitalize and evaluate the assets as a part of its producing well properties. Therefore, our ability to recover the carrying amount of our investment lies in the value of our producing well assets that utilize these gathering systems. As of December 31, 2011, we determined that we had the ability to recover the carrying amount of our investment in RW Gathering.

Keystone Midstream

On September 30, 2010, we sold 30% of our interest in Keystone Midstream Services, LLC ("Keystone Midstream") to Sumitomo, decreasing our ownership of the entity to 28% and triggering a re-evaluation of the consolidation analysis. Due to our decreased ownership in Keystone Midstream and our decreased ownership of the Butler County, Pennsylvania assets to be serviced by Keystone Midstream (see Note 3, *Business and Oil and Gas Property Acquisitions and Dispositions*, to our Consolidated Financial Statements); we no longer have the power to direct the activities that most significantly impact the entity's economic performance. Thus, we are no longer considered the primary beneficiary of Keystone Midstream and have deconsolidated the operations as of September 1, 2010, the effective date of the sale.

As of September 1, 2010, we accounted for our 28% ownership interest in Keystone Midstream via the equity method. Prior to September 1, 2010, Keystone Midstream was a consolidated VIE. Under the equity method, we recorded our investment in Keystone Midstream of approximately \$26.0 million and \$12.0 million as of December 31, 2011 and 2010, respectively, on our Consolidated Balance Sheet as Equity Method Investments. In 2011 and 2010, we contributed approximately \$13.5 million and \$9.6 million, respectively, to Keystone Midstream primarily support the construction of cryogenic gas processing plants. Keystone Midstream recorded net income from continuing operations of \$1.6 million for the year ended December 31, 2011, and a net loss of \$0.5 million for the four month period ended December 31, 2010.

Prior to September 1, 2010, we consolidated the operations of Keystone Midstream, where the noncontrolling interest's share of net loss was recorded as Net Loss Attributable to Noncontrolling Interests. Subsequent to September 1, 2010, we record our share of net losses related to Keystone Midstream as Loss on

Equity Method Investments on our Consolidated Statement of Operations. Our share of losses incurred to date under the equity method of accounting are primarily due to project management costs, general and administrative expenses, and DD&A expenses and totaled approximately \$0.5 million and \$0.1 million for the years ended December 31, 2011 and 2010, respectively.

When evaluating our Equity Method Investments for impairment we review our ability to recover the carrying amount of such investments or the entity's ability to sustain earnings that justify its carrying amount. In the case of Keystone Midstream, the entity has justified its ability to sustain earnings that justify its carrying amount through the capacity reservation fee (see Note 8, *Commitments and Contingencies*, to our Consolidated Financial Statements). The capacity reservation fee provides guaranteed cash flows to the equity group.

7. CONCENTRATIONS OF CREDIT RISK

At times during the years ended December 31, 2011 and 2010, our cash balance may have exceeded the Federal Deposit Insurance Corporation's limit of \$250,000. There were no losses incurred due to such concentrations.

By using derivative instruments to hedge exposure to changes in commodity prices, we are exposed to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of the derivative is positive, the counterparty owes us, which creates repayment risk. We minimize the credit or repayment risk in derivative instruments by entering into transactions with four high-quality counterparties. Our counterparties are investment grade financial institutions, and lenders in our Senior Credit Facility. We have a master netting agreement in place with our counterparties that provides for the offsetting of payables against receivables from separate derivative contracts. None of our derivative contracts have a collateral provision that would require funding prior to the scheduled settlement date. For additional information, see Note 2, Summary of Significant Accounting Policies, and Note 11, Fair Value of Financial Instruments and Derivative Instruments, to our Consolidated Financial Statements.

We also depend on a relatively small number of purchasers for a substantial portion of our revenue. At December 31, 2011, we carried approximately \$13.6 million in production receivables, of which approximately \$12.9 million were production receivables due from three purchasers. At December 31, 2010, we carried approximately \$8.1 million in production receivable, of which approximately \$7.3 million were production receivables due from five purchasers. We believe the growth in our Appalachian estimated proved reserves will help us to minimize our future risks by diversifying our ratio of oil and gas sales as well as the quantity of purchasers.

8. COMMITMENTS AND CONTINGENCIES

Legal Reserves

At December 31, 2011, our Consolidated Balance Sheet included approximately \$0.1 million in reserve for the legal matters referenced in Note 24—*Litigation*. At December 31, 2010, our Consolidated Balance Sheet included \$0.2 million in reserve for various legal proceedings. The accrual of reserves for legal matters is included in Accrued Expenses on the Consolidated Balance Sheets. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that we could incur additional loss, the amount of which is not currently estimable, in excess of the amounts currently accrued with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in actual liability exceeding the estimated ranges of loss and the amounts accrued. Based on currently available information, we believe that it is remote that future costs related to known contingent liability exposures for legal proceedings will exceed current accruals by an amount that would have a material adverse effect on our consolidated financial position or results of operations, although cash flow could be significantly impacted in the reporting periods in which such costs are incurred.

Acreage Bonus Payments

At December 31, 2011, we had installment payment commitments on mineral interests that were previously leased in the amount of \$1.2 million. All of these commitments are expected to be paid in 2012 and have been classified as Accrued Expenses on our Consolidated Balance Sheet. At December 31, 2010, our liability for installment payment commitments on mineral interests totaled approximately \$5.2 million, with \$1.7 million classified as Accrued Expenses and \$3.5 million classified as Other Deposits and Liabilities on our Consolidated Balance Sheet.

Environmental

Due to the nature of the natural gas and oil business, we are exposed to possible environmental risks. We have implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. We conduct periodic reviews to identify changes in the environmental risk profile. These reviews evaluate whether there is a probable liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate salaries and wages cost of employees who are expected to devote a significant amount of time directly to any remediation effort.

We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Except for contingent liabilities associated with the consent decree with the U.S. EPA relating to alleged H₂ S emissions in the Lawrence Field, we know of no significant probable or possible environmental contingent liabilities.

Letters of Credit

We have posted \$0.8 million, at December 31, 2011 and December 31, 2010, in various letters of credit to secure our drilling and related operations.

Lease Commitments

At December 31, 2011 we have lease commitments for various real estate leases. Rent expense from continuing operations has been recorded in General and Administrative expense as \$0.4 million, \$0.3 million and \$0.4 million for the years ended December 31, 2011, 2010 and 2009, respectively. Lease commitments by year for each of the next five years are presented in the table below (\$ in thousands).

2012	\$ 497
2013	548
2014	104
2015	44
2016	0
Thereafter	0
Total	\$1,193

Capacity Reservation

In connection with the formation of Keystone Midstream (see Note 6, *Equity Method Investments*, to our Consolidated Financial Statements), we entered into a capacity reservation arrangement with Keystone Midstream to ensure sufficient capacity at the Sarsen cryogenic gas processing plant to process our produced natural gas. Under the terms of the arrangement, we reserved 14 Mmcfe of net processing capacity per day for the first year of operations, effective in February 2011, and 28 Mmcfe of net processing capacity for the

subsequent nine years of operation, or through January 2020. If we do not meet our capacity reservation volumes, we are obligated to pay \$0.30/Mcfe per day for the difference between actual processed volumes and the reservation volume. In the event that we do not process any gas through the cryogenic gas processing plant we may be obligated to pay approximately \$2.9 million in 2012, \$3.1 million for each year from 2013 through 2019, and \$0.3 million in 2020. As of December 31, 2011, our production has increased to levels maximizing the current plant capacity.

Operational Commitments

Pursuant to agreements reached during the fourth quarter of 2010 and the first quarter of 2011, we have contracted drilling rig services on two rigs to support our Butler County, Pennsylvania operations. The minimum cost to retain these rigs would require payments of approximately \$1.1 million in 2012 and \$0.1 million in 2013, which is consistent with our 70% working interest in this project area. In addition, during the first quarter of 2011 we came to terms on contracted completion services in Butler County, Pennsylvania. The minimum cost to retain the completion services is approximately \$8.4 million in 2012 and \$2.1 million in 2013, which is consistent with our 70% working interest in this project area.

Natural Gas Gathering, Processing and Sales Agreements

Under a natural gas sales agreement with BP Energy Company ("BP Energy"), we have agreed to supply natural gas to BP Energy at certain delivery points in Pennsylvania with a termination date expected to be December 31, 2022, unless terminated earlier under certain conditions specified in the sales agreement. During the term of the sales agreement, we are obligated to provide to BP Energy, and BP Energy is obligated to purchase from us, a minimum monthly volume of natural gas equivalent to 17,500 MMBtu of natural gas per day from March 1, 2012 to December 31, 2012 and 59,500 MMBtu per day after January 1, 2013. On all volumes delivered, and on any shortfalls between volumes delivered and the minimum monthly quantity, we are obligated to pay a marketing fee and a demand charge. In connection with the entry into the sales agreement, we concurrently entered into a guaranty agreement whereby we have guaranteed the payment of obligations under the sales agreement up to a maximum of \$50.0 million.

During the fourth quarter of 2011, we entered into gathering and processing agreements with Dominion East Ohio ("Dominion East") and Dominion Natrium, LLC ("Dominion Natrium"), respectively, to transport and process anticipated natural gas and natural gas liquid production in Ohio. Under the gathering agreement, we have agreed to supply natural gas at certain delivery points in Ohio for a 10-year primary term, which is anticipated to begin on October 1, 2012. During the term of the gathering agreement, Dominion East is obligated to transport a maximum of 15,000 mcf per day and we are obligated to pay a fee based on the volumes transported. Under the processing agreement, we have agreed to supply natural gas at Dominion Natrium's processing and fractionation facility in Natrium, West Virginia for a 10-year primary term, which is anticipated to begin on December 1, 2012. During the term of the processing agreement, Dominion Natrium is obligated to process a maximum of 15,000 mcf per day and we are obligated to pay a reservation fee.

In coordination with the aforementioned gathering and processing agreements, we have entered into an additional natural gas sales agreement with BP Energy, where we are obligated to sell, and BP Energy is obligated to purchase, 14,000 MMBtu per day of natural gas, for which we will pay a marketing fee and demand charge. The effective date of the sales agreement is expected to be no sooner than November 1, 2014 and will last until December 31, 2022.

Minimum net obligations under these sales, gathering and transportation agreements for the next five years (\$ in thousands):

	BP Energy	Dominion East(a)	Dominion Natrium(a)	Total
2012	\$ 624	\$ 345	\$ 195	\$ 1,164
2013	2,531	1,369	2,300	6,200
2014	2,673	1,369	2,300	6,342
2015	3,382	1,369	2,300	7,051
2016	3,382	1,369	2,300	7,051
Thereafter	21,143	7,868	13,602	42,613
Total	\$33,735	\$13,689	\$22,997	\$70,421

⁽a) Assumes 100% working interest, actual working interest could be materially different as drilling units are formed.

Other

In addition to the asset retirement obligation discussed in Note 2, *Summary of Significant Accounting Policies*, we have withheld from distributions to certain other working interest owners amounts to be applied towards their share of those retirement costs. Such amounts, totaling \$0.3 million, are included in Other Deposits and Liabilities at December 31, 2011 and December 31, 2010, respectively.

9. RELATED PARTY TRANSACTIONS

Aircraft Services

We currently have an oral month-to-month agreement with Charlie Brown Air Corp. ("Charlie Brown"), a New York corporation owned by Lance T. Shaner, our Chairman, regarding the use of two airplanes owned by Charlie Brown. Under our agreement with Charlie Brown, we pay a monthly fee for the right to use the airplanes equal to our percentage (based upon the total number of hours of use of the airplanes by us) of the monthly fixed costs for the airplanes, plus a variable per hour flight rate that ranges from \$400 to \$1,850 per hour. In September 2010, we purchased an undivided 50% interest in one of these airplanes, a Cessna model 550 from Charlie Brown for approximately \$0.6 million. In April 2011, we purchased the remaining 50% interest in this aircraft for approximately \$0.6 million. The purchase of the aircraft has been recorded as Other Property and Equipment on our Consolidated Balance Sheets. For the years ended December 31, 2011, 2010 and 2009, we paid Charlie Brown \$0.2 million, \$0.4 million and \$0.1 million, respectively, for the use of the aircrafts, including the variable per hour cost in addition to pilots fees, maintenance, hangar rental and other miscellaneous expenses.

We own a 25% membership interest in Charlie Brown Air II, LLC ("Charlie Brown II"). Shaner Hotel Group Limited Partnership, a Delaware limited partnership controlled by Mr. Lance T. Shaner ("Shaner Hotel"), and an unrelated third party each own 25% and 50%, respectively, in Charlie Brown II, which owns and operates an Eclipse 500 aircraft, which was purchased for approximately \$1.7 million.

Charlie Brown II has a loan from Graystone Bank to purchase the aircraft that was originally \$1.5 million at its inception in June 2007. The loan matures on June 21, 2017 and bears interest at a rate of LIBOR plus 2.5%. The loan required payments of interest only for the first three months of the loan. Thereafter, Charlie Brown II has been required to make monthly payments of principal and interest utilizing an amortization period of 180 months. The Company and Shaner Hotel each guarantee up to twenty five percent, or \$0.4 million, of the principal balance of the loan. The balance of this loan as of December 31, 2011 and 2010 was approximately \$0.5 million and \$1.4 million, respectively. For the years ended December 31, 2011, 2010 and 2009, we paid Charlie Brown II approximately \$0.2 million each year, respectively, for loan interest, services rendered and retainer fees.

The business affairs of Charlie Brown Air II, LLC are managed by three members, appointed by each of its three owners. We have designated Thomas C. Stabley, our Chief Executive Officer, as the manager representing our membership interest. Actions of the company must be approved by a majority of the interest percentages of the managers. Each manager votes in matters before the company in accordance with the membership interest percentage of the member that appointed the manager. Certain events, such as the sale by a member of its interest, the merger or consolidation of the company, the filing of bankruptcy, or the sale of the airplane owned by Charlie Brown Air II, LLC, require the written consent of all managers. The consent of managers is also required before the company may change or terminate the management agreement with Charlie Brown, incur any indebtedness, sell substantially all of the company's assets or sell the airplane owned by the company. In the event that the members are unable to unanimously agree upon any of these matters within 10 days of the proposal of any such matter, an "impasse" may be declared, and the airplane will be sold by the company.

RW Gathering, LLC

Pursuant to the terms of the Williams PEA, we and Williams agreed to form RW Gathering to own any gas-gathering assets which we agreed to jointly construct in order to facilitate the development of our Project Area (see Note 6, *Equity Method Investments*, to our Consolidated Financial Statements). For the years ended December 31, 2011 and 2010, we incurred approximately \$0.8 million and \$0.2 million, respectively, in compression expenses that were charged to us from Williams Production Appalachia, LLC. These costs are in relation to compression costs incurred by RW Gathering and are recorded as Production and Lease Operating Expense on our Consolidated Statement of Operations. As of December 31, 2011 and 2010, there were no receivables or payables in relation to RW Gathering due to or from us.

Keystone Midstream

We incurred approximately \$4.6 million and \$0.3 million in transportation and processing expenses that were charged to us from Keystone Midstream during 2011 and 2010, respectively (see Note 6, *Equity Method Investments*, to our Consolidated Financial Statements). Prior to September 1, 2010, charges incurred for transportation were eliminated in consolidation. Subsequent to August 31, 2010, such transportation charges are recorded as Production and Lease Operating Expense on our Consolidated Statements of Operations. As of December 31, 2011, we had Accrued Expenses due to Keystone Midstream of approximately \$0.5 million, which was inclusive of transportation and processing expenses incurred during December 2011. As of December 31, 2010, we had Accrued Expenses due to Keystone Midstream of approximately \$1.3 million, which was comprised of \$0.1 million in transportation and processing expenses incurred during the fourth quarter 2010 and \$1.2 million in expenses due from us to fund the acceleration of the Sarsen cryogenic gas processing plant construction. There were no related party expenses or amounts due to or from us to Keystone Midstream prior to January 1, 2010.

Water Solutions

We incurred approximately \$1.6 million and \$0.4 million in water transfer and water purification expenses that were charged to us from Water Solutions during 2011 and 2010, respectively (see Note 5, *Variable Interest Entities*, to our Consolidated Financial Statements). We have eliminated these charges in consolidation. As of December 31, 2011, we had payables of approximately \$0.3 million to Water Solutions for work performed during the period, which were eliminated in consolidation. As of December 31, 2010, we did not have any payables due to Water Solutions.

NorthStar #3, LLC

During 2011, we paid approximately \$4.9 million in expenses related to the drilling of a water disposal well on behalf of NorthStar #3 (see note 5, *Variable Interest Entities*, to our Consolidated Financial Statements). This amount has been recorded in a promissory note due to us from NorthStar #3, bearing 5% interest. The

promissory note has been eliminated in consolidation, while the cost of the well has been recorded as Wells and Facilities in Progress on our Consolidated Balance Sheet. As of December 31, 2011, there were no amounts due to NorthStar #3 or due to us from NorthStar #3 with exception to the promissory note. NorthStar #3 did not exist prior to 2011.

10. LONG-TERM DEBT

Senior Credit Facility

We maintain a revolving credit facility evidenced by the Credit Agreement, dated September 28, 2007, with KeyBank, as Administrative Agent; Royal Bank of Canada, as Syndication Agent; Sovereign Bank, as Documentation Agent; and lenders from time to time parties thereto (as amended from time to time, the "Senior Credit Facility"). Borrowings under the Senior Credit Facility are limited by a borrowing base that is determined in regard to our oil and gas properties. The borrowing base under the Senior Credit Facility is currently \$255.0 million; however, the revolving credit facility may be increased up to \$500 million upon re-determinations of the borrowing base, consent of the lenders and other conditions prescribed in the agreement. The Senior Credit Facility provides that the borrowing base will be re-determined semi-annually by the lenders, in good faith, based on, among other things, reports regarding our oil and gas reserves attributable to our oil and gas properties, together with a projection of related production and future net income, taxes, operating expenses and capital expenditures. We may, or the Administrative Agent at the direction of a majority of the lenders may, each elect once per calendar year to cause the borrowing base to be re-determined between the scheduled re-determinations. In addition, we may request interim borrowing base re-determinations upon our proposed acquisition of proved developed producing oil and gas reserves with a purchase price for such reserves greater than 10% of the then borrowing base. As of December 31, 2011, loans made under the Senior Credit Facility were set to mature on September 28, 2015. In certain circumstances, we may be required to prepay the loans. Management does not believe that a prepayment will be required within the next twelve months. As of December 31, 2011, we had \$175.0 million drawn on the Senior Credit Facility as compared to \$10.0 million at December 31, 2010.

Borrowings under the Senior Credit Facility bear interest, at our election, at the Adjusted LIBOR or the Alternative Base Rate (as defined below) plus, in each case an applicable per annum margin. The applicable per annum margin is determined based upon our total borrowing base utilization percentage in accordance with a pricing grid. The applicable per annum margin ranges from 1.75% to 2.75% for Eurodollar loans and .50% to 1.50% for ABR loans. The Adjusted Base Rate is equal to the greater of: (i) KeyBank's announced prime rate; (ii) the federal funds effective rate from time to time plus ½ of 1%; and (iii) LIBOR plus 1.25%. Our commitment fee is also dependent on our total borrowing base utilization percentage and is determined based upon an applicable per annum margin which ranges from 0.375% to 0.50%.

Under the Senior Credit Facility, we may enter into commodity swap agreements with counterparties approved by the lenders, provided that the notional volumes for such agreements, when aggregated with other commodity swap agreements then in effect (other than basis differential swaps on volumes already hedged pursuant to other swap agreements), do not exceed, as of the date the swap agreement is executed, 85% of the reasonably anticipated projected production from our proved developed producing reserves for the 36 months following the date such agreement is entered into, and 75% thereafter, for each of crude oil and natural gas, calculated separately. We may also enter into interest rate swap agreements with counterparties approved by the lenders that convert interest rates from floating to fixed provided that the notional amounts of those agreements, when aggregated with all other similar interest rate swap agreements then in effect, do not exceed the greater of \$20 million and 75% of the then outstanding principal amount of our debt for borrowed money which bears interest at a floating rate.

The Senior Credit Facility contains covenants that restrict our ability to, among other things, materially change our business; approve and distribute dividends; enter into transactions with affiliates; create or acquire additional subsidiaries; incur indebtedness; sell assets; make loans to others; make investments; enter into

mergers; incur liens; and enter into agreements regarding swap and other derivative transactions (for further information, see Note 2, Summary of Significant Accounting Policies, Note 7, Concentrations of Credit Risk, and Note 11, Fair Value of Financial Instruments and Derivative Instruments, to our Consolidated Financial Statements). Borrowings under the Senior Credit Facility have been used to finance our working capital needs and for general apporate purposes in the ordinary course of business, including the exploration, acquisition and development of oil and gas properties. Obligations under the Senior Credit Facility are secured by mortgages on the oil and gas properties of our subsidiaries located in the states of Illinois and Indiana. We are required to maintain liens covering our oil and gas properties representing at least 80% of our total value of all oil and gas properties.

The Senior Credit Facility also requires we meet, on a quarterly basis, minimum financial requirements of consolidated current ratio, EBITDAX to interest expense and total debt to EBITDAX. EBITDAX is a non-GAAP financial measure used by our management team and by other users of our financial statements, such as our commercial bank lenders, which adds to or subtracts from net income the following expenses or income for a given period to the extent deducted from or added to net income in such period: interest, income taxes, depreciation, depletion, amortization, unrealized gains and losses from derivatives, exploration expense and other similar non-cash activity. The Senior Credit Facility requires that as of the last day of any fiscal quarter, our ratio of consolidated current assets, which includes the unused portion of our borrowing base, as of such day to consolidated current liabilities as of such day, known as our current ratio, must not be less than 1.0 to 1.0. Our current ratio as of December 31, 2011 was approximately 2.8 to 1.0. Additionally, the Senior Credit Facility requires that as of the last day of any fiscal quarter, our ratio of EBITDAX for the period of four fiscal quarters ending on such day to interest expense for such period, known as our interest coverage ratio, must not be less than 3.0 to 1.0. Our interest coverage ratio as of December 31, 2011 was approximately 19.8 to 1.0. Additionally, as of the last day of any fiscal quarter, our ratio of total debt to EBITDAX for the period of four fiscal quarters ending on such day must not exceed 4.25 to 1.0. Our ratio of total debt to EBITDAX as of December 31, 2011 was approximately 2.9 to 1.0.

Second Lien Credit Agreement

On December 22, 2011, we entered into a second lien credit agreement (the "Second Lien Credit Agreement") with KeyBank, as administrative agent, Wells Fargo Bank, N.A., as syndication agent, UnionBanCal Equities, Inc. and SunTrust Bank, as co-documentation agents, and the lenders from time to time party thereto. The Second Lien Credit Agreement provides for a \$100.0 million senior secured second lien term loan facility under which \$50.0 million is initially available to us and up to an additional \$50.0 million of incremental borrowings may be available upon the request of the Company. The initial borrowings under the Second Lien Credit Agreement mature on March 28, 2016. The maturity of incremental borrowings will be determined at the time of such borrowings. In certain circumstances, we may be required to prepay borrowings under the Second Lien Credit Agreement. Management does not believe that a prepayment will be required within the next twelve months.

At our election, borrowings under the Second Lien Credit Agreement bear interest at a rate per annum equal to the "Alternate Base Rate" or "Adjusted LIBOR" (each as defined below), plus, in each case, an applicable per annum margin. The Alternative Base Rate is equal to the greater of: (i) KeyBank's announced prime rate; (ii) the federal funds effective rate from time to time plus 0.5%; and (iii) the London Interbank Offered Rate for deposits with a maturity comparable to the borrowings (provided that such rate shall never be less than 1.0%) ("LIBOR Rate") plus 1.0%. Adjusted LIBOR equals the product of the LIBOR Rate multiplied by a statutory reserve rate. The applicable per annum margin equals, in the case of loans bearing interest at the Alternate Base Rate, 5.0% through the first anniversary of the initial borrowings and 6.0% thereafter, and in the case of Adjusted LIBOR loans, 6.0% through the first anniversary of the initial borrowings and 7.0% thereafter. Interest is payable quarterly in the case of loans bearing interest at the Alternate Base Rate and on the last day of each relevant interest period or every three months in the case of loans bearing interest at the Adjusted LIBOR.

The Second Lien Credit Agreement contains covenants that restrict our ability to, among other things, materially change our business, make dividends, enter into transactions with affiliates, create or acquire additional subsidiaries, incur indebtedness, sell assets, make loans to others, make investments, enter into mergers, incur liens, and enter into agreements regarding swap and other derivative transactions. The Second Lien Credit Agreement states that as of the last day of any fiscal quarter, our current ratio must not be less than 1.0 to 1.0. Our current ratio as of December 31, 2011 was approximately 2.8 to 1.0. Additionally, the Second Lien Credit Agreement states that as of the last day of any fiscal quarter, our interest coverage ratio for the period of four fiscal quarters ending on such day must not to be less than 3.0 to 1.0. Our interest coverage ratio as of December 31, 2011 was approximately 19.8 to 1.0. Additionally, as of the last day of any fiscal quarter, our ratio of total debt to EBITDAX for the period of four fiscal quarters ending on such day is not to exceed 4.25 to 1.0. Our ratio of total debt to EBITDAX as of December 31, 2011 was approximately 2.9 to 1.0. Obligations under the Second Lien Credit Agreement are secured by mortgages on our oil and gas properties. We are required to maintain liens covering our oil and gas properties representing at least 80% of the total value of all of our oil and gas properties.

In connection with the Second Lien Agreement, we entered into a guaranty and second lien collateral agreement, dated as of December 22, 2011, in favor of KeyBank, as administrative agent for the banks and other financial institutions from time to time party to the Second Lien Credit Agreement ("the "Guaranty and Second Lien Collateral Agreement"). Pursuant to the Guaranty and Second Lien Collateral Agreement, we, jointly and severally, guaranteed the prompt and complete payment of our obligations under the Second Lien Credit Agreement. In addition, we granted, as security for the prompt and complete payment and performance when due of such obligations, a security interest in substantially all of our personal property, including equity interests.

As of December 31, 2011, we had \$50.0 million drawn on the Second Lien Credit Agreement, for which we used the proceeds to finance the acquisition of certain oil and gas leases in Ohio and Pennsylvania, pay amounts outstanding under our the Senior Credit Facility, and for other general corporate purposes.

In addition to our Senior Credit Facility and Second Lien Credit Agreement, we may, from time to time in the normal course of business, finance assets such as vehicles, office equipment and leasehold improvements through debt financing at favorable terms. Long-term debt and lines of credit consists of the following at December 31, 2011 and 2010:

	December 31, 2011 (in thousands)	December 31, 2010 (in thousands)
Senior-Secured Lines of Credit(a)	\$225,000 544	\$10,000 949
Total Debts	225,544 (406)	10,949 (829)
Total Long-Term Debts	\$225,138	\$10,120

⁽a) The average interest rate on borrowings under our Senior Credit Facility for the year ended December 31, 2011 was approximately 2.5%. The average interest rate on borrowings under the Second Lien Credit Agreement for the year ended December 31, 2011 was approximately 8.3%. The average interest rate on our Other Loans and Notes Payable is approximately 2.3%. The average interest rate on borrowings under our Senior Credit Facility for the year ended December 31, 2010 was approximately 2.3%. The average interest rate on our Other Loans and Notes Payable is approximately 2.4%.

⁽b) Classified as Accounts Payable on our Consolidated Balance Sheets.

The following is the principal maturity schedule for debt outstanding as of December 31, 2011:

	Year Ended December 31, (in thousands)
2012	\$ 406
2013	138
2014	0
2015	175,000
2016	
Thereafter	0
Total	

11. FAIR VALUE OF FINANCIAL INSTRUMENTS AND DERIVATIVE INSTRUMENTS

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we enter into oil and natural gas commodity derivative instruments to establish price floor protection. As such, when commodity prices decline to levels that are less than our average price floor, we receive payments that supplement our cash flows. Conversely, when commodity prices increase to levels that are above our average price ceiling, we make payments to our counterparties. We do not enter into these arrangements for speculative trading purposes. As of December 31, 2011, 2010 and 2009, our oil and natural gas derivative commodity instruments consisted of fixed rate swap contracts, puts, collars, swaptions and put spreads. We did not designate these instruments as cash flow hedges for accounting purposes. Accordingly, associated unrealized gains and losses are recorded directly as Gain (Loss) on Derivatives, Net. For additional information, see Note 2, Summary of Significant Accounting Policies, to our Consolidated Financial Statements.

Swap contracts provide a fixed price for a notional amount of sales volumes. Collars contain a fixed floor price ("put") and ceiling price ("call"). The put options are purchased from the counterparty by our payment of a cash premium. If the put strike price is greater than the market price for a settlement period, then the counterparty pays us an amount equal to the product of the notional quantity multiplied by the excess of the strike price over the market price. The call options are sold to the counterparty, for which we receive a cash premium. If the market price is greater than the call strike price for a settlement period, then we pay the counterparty an amount equal to the product of the notional quantity multiplied by the excess of the market price over the strike price. A three-way collar is a combination of options, a sold call, a purchased put and a sold put. The purchased put establishes a minimum price unless the market price falls below the sold put, at which point the minimum price would be the settlement price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price we will receive for the volumes under contract. Swaption agreements provide options to counterparties to extend swaps into subsequent years.

We enter into the majority of our derivative arrangements with four counterparties and have a netting agreement in place with these counterparties. We do not obtain collateral to support the agreements, but we believe our credit risk is currently minimal on these transactions. For additional information on the credit risk regarding our counterparties, see Note 7, *Concentrations of Credit Risk*, to our Consolidated Financial Statements.

None of our derivatives are designated for hedge accounting but are, to a degree, an economic offset to our oil and natural gas price exposure. We utilize the mark-to-market accounting method to account for these contracts. We recognize all unrealized and realized gains and losses related to these contracts in the Consolidated Statements of Operations as Gain (Loss) on Derivatives, Net under Other Income (Expense).

We received net cash receipts from continuing operations of \$6.2 million, \$0.1 million and \$9.6 million for the years ended December 31, 2011, 2010 and 2009, respectively. During the first quarter of 2009, we redeemed our oil

hedges related to production in 2011 for net cash proceeds of approximately \$4.6 million. Unrealized gains and losses from continuing operations associated with our derivative instruments amounted to a gain of \$12.7 million and \$6.0 million and a loss of \$17.6 million for the years ended December 31, 2011, 2010 and 2009, respectively.

The following table summarizes the location and amounts of gains and losses on derivative instruments from continuing operations, none of which are designated as hedges for accounting purposes, in our accompanying Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009:

Year Ended December 31, 2011 (in thousands)	
Realized Unrealized Gains Gains (Losses) (Losses) Total	•
	Crude Oil
\$ 0 \$ 1,850 \$ 1,850 0 (1,488) (1,488)	Reclassification of settled contracts included in prior periods mark-to-mark adjustments Mark-to-market fair value adjustments Settlement of contracts(a)
(670) 362 (308)	Crude Oil Total
	Natural Gas Reclassification of settled contracts included in prior periods mark-to-mark
$0 \qquad (4,231) \qquad (4,231)$	adjustments
0 16,573 16,573	Mark-to-market fair value adjustments
6,882 0 6,882	Settlement of contracts(a)
	Natural Gas Total
$ \begin{array}{cccccccccccccccccccccccccccccccccccc$	Reclassification of settled contracts included in prior periods mark-to-mark adjustments Mark-to-market fair value adjustments Settlement of contracts(a) Crude Oil Total Natural Gas Reclassification of settled contracts included in prior periods mark-to-mark adjustments Mark-to-market fair value adjustments Settlement of contracts(a) Natural Gas Total

⁽a) These amounts represent the realized gains and losses on settled derivatives, which before settlement are included in the mark-to-market fair value adjustments.

		led December in thousands	
	Realized Gains (Losses)	Unrealized Gains (Losses)	Total
Crude Oil			
Reclassification of settled contracts included in prior periods mark-to-market			
adjustments	\$ 0	\$ 5,782	\$ 5,782
Mark-to-market fair value adjustments	0	(2,819)	(2,819)
Settlement of contracts(a)	(3,861)	0	(3,861)
Crude Oil Total	(3,861)	2,963	(898)
Natural Gas	, , ,		, ,
Reclassification of settled contracts included in prior periods mark-to-market			
adjustments	0	(1,925)	(1,925)
Mark-to-market fair value adjustments	0	4,211	4,211
Settlement of contracts(a)	4,667	0	4,667
Natural Gas Total	4.667	2,286	6,953
Interest Rate	,,007	2,200	0,755
Reclassification of settled contracts included in prior periods mark-to-market			
adjustments	0	711	711
Mark-to-market fair value adjustments	0	0	0
Settlement of contracts(a)	(711)	0	(711)
Interest Rate Total	$\overline{(711)}$	711	0
Gain (Loss) on Derivatives, Net	\$ 95	\$ 5,960	\$ 6,055
Cam (Boss) on Politarios, 100		ψ 5,500	======

⁽a) These amounts represent the realized gains and losses on settled derivatives, which before settlement are included in the mark-to-market fair value adjustments.

	Year Ended December 31, 2009 (in thousands)		
	Realize Gains (Losses	Gains	Total
Crude Oil			
Reclassification of settled contracts included in prior periods mark-to-market			
adjustments	\$ (0 \$(10,331)	\$(10,331)
Mark-to-market fair value adjustments	((8,114)	(8,114)
Settlement of contracts(a)	7,19	80	7,198
Crude Oil Total	7,19	8 (18,445)	(11,247)
Natural Gas			
Reclassification of settled contracts included in prior periods mark-to-market			
adjustments	((1,091)	(1,091)
Mark-to-market fair value adjustments	(1,518	1,518
Settlement of contracts(a)	3,210	5 0	3,216
Natural Gas Total	3,210	6 427	3,643
Interest Rate	,		,
Reclassification of settled contracts included in prior periods mark-to-market			
adjustments	(0 611	611
Mark-to-market fair value adjustments	($0 \qquad (151)$	(151)
Settlement of contracts(a)	(769	9) 0	(769)
Interest Rate Total	(769	9) 460	(309)
Gain (Loss) on Derivatives, Net	\$9,64	<u>\$(17,558)</u>	\$ (7,913)

⁽a) These amounts represent the realized gains and losses on settled derivatives, which before settlement are included in the mark-to-market fair value adjustments.

Our derivative instruments are recorded on the balance sheet as either an asset, or a liability, measured at its fair value. The fair value associated with our derivative instruments was an asset of approximately \$15.3 million and \$2.6 million at December 31, 2011 and 2010, respectively. The fair value is based on the valuation methodologies of our counterparties and third-party valuation providers. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

Our open asset/(liability) financial commodity derivative instrument positions at December 31, 2011 consisted of:

Period	Volume	Put Option	Floor	Ceiling	Swap	Fair Market Value (\$ in Thousands)
<u>Oil</u>						
2012—Collar	660,000 Bbls	\$ 0	\$69.44	\$110.21	\$ 0	\$ (2,363)
2013—Collar	300,000 Bbls	0	72.40	116.30	0	(490)
	960,000 Bbls					\$ (2,853)
Natural Gas						
2012—Swap	2,400,000 Mcf	\$ 0	\$ 0	\$ 0	\$5.04	\$ 3,912
2012—Swaption	600,000 Mcf	. 0	0	0	5.25	1,047
2012—Collar	3,000,000 Mcf	0	4.70	5.89	0	4,112
2012—3-Way Collar	2,640,000 Mcf	3.66	4.48	5.13	0	1,333
2013—Put	2,640,000 Mcf	0	5.00	0	0	2,730
2013—Swap	2,880,000 Mcf	0	0	0	4.30	1,377
2013—Collar	3,360,000 Mcf	0	4.77	5.68	0	3,465
2013—3-Way Collar	1,920,000 Mcf	3.53	4.38	5.08	0	861
2014—Call	1,800,000 Mcf	0	0	5.00	0	(642)
	21,240,000 Mcf					\$18,195

The combined fair value of derivatives, none of which are designated or qualifying as hedges, included in our Consolidated Balance Sheets as of December 31, 2011 and December 31, 2010 is summarized below.

	December 31, 2011 (in thousands)	December 31, 2010 (in thousands)
Short-Term Derivative Assets:		-
Natural Gas—Swaption	\$ 1,047	\$ 0
Natural Gas—Swaps	3,912	519
Natural Gas—Collars	4,112	1,132
Natural Gas—3-Way Collars	1,333	0
Natural Gas—Puts	0	2,464
Natural Gas—Put Spread	0	449
Total Short-Term Derivative Assets	\$10,404	\$ 4,564
Long-Term Derivative Assets:		
Crude Oil—Collars	\$ 143	\$ 63
Natural Gas—Swaps	1,377	663
Natural Gas—3-Way Collars	861	0
Natural Gas—Put	505	0
Natural Gas—Collars	5,690	723
Total Long-Term Derivative Assets	\$ 8,576	\$ 1,449
Total Derivative Assets	\$18,980	\$ 6,013
Short-Term Derivative Liabilities:		
Crude Oil—Collars	\$ (2,363)	\$(1,850)
Natural Gas—Collars	0	(10)
Total Short-Term Derivative Liabilities	\$ (2,363)	\$(1,860)
Long-Term Derivative Liabilities:		
Crude Oil—Collars	\$ (632)	\$(1,428)
Natural Gas—Call	(643)	0
Natural Gas—Collars	0	(88)
Total Long-Term Derivative Liabilities	<u>\$(1,275)</u>	\$(1,516)
Total Derivative Liabilities	\$ (3,638)	\$(3,376)

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to utilize the best available information. We utilize a fair value hierarchy that gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date.

Level 2—Pricing inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that

consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps and collars, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

The following table presents the fair value hierarchy table for assets and liabilities measured at fair value (\$ in thousands):

		Fair Value Me	asurements at 2011 Using:	December 31,
	Total Carrying Value as of December 31, 2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Derivatives(a)—commodity swaps, collars and put				
options	\$ 15,342	\$0	\$15,342	\$ 0
Asset Retirement Obligations	\$(18,670)	\$0	\$ 0	\$(18,670)

⁽a) All of our derivatives are classified as Level 2 measurements. For information regarding their classification on our Consolidated Balance Sheets, please refer to the table on page 73 of this report.

Our derivative contracts are valued by third parties using valuation models that are primarily industry-standard models that consider various inputs including: quoted forward prices; time value; volatility factors; and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. We classify our derivatives as Level 2 if the inputs used in the valuation models are directly observable for substantially the full term of the instrument; however, if the significant inputs were not observable for substantially the full term of the instrument, we would classify those derivatives as Level 3. We categorize our measurements as Level 2 because the valuation of our derivative commodity swaps and collars and interest rate swaps are based on similar transactions observable in active markets or industry standard models that primarily rely on market observable inputs. Substantially all of the assumptions for industry standard models are observable in active markets throughout the full term of the instruments.

Asset Retirement Obligations

We report the fair value of asset retirement obligations on a nonrecurring basis in our Consolidated Balance Sheets. We estimate the fair value of asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an asset retirement obligation; estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. These inputs are unobservable, and thus result in a Level 3 classification. See Note 2, *Summary of Significant Accounting Policies*, to our Consolidated Financial Statements for further information on asset retirement obligations, which includes a reconciliation of the beginning and ending balances which represent the entirety of our Level 3 fair value measurements.

12. INCOME TAXES

We recognize deferred tax liabilities and assets for the expected future tax consequences of events that may be recognized in our financial statements or tax returns. Using this method, deferred tax liabilities and assets are determined based on the difference between the financial carrying amounts and tax bases of assets and liabilities using enacted tax rates. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

All information in the tables below includes results from continuing operations and discontinued operations.

	Year Ended December 31, 2011 (in thousands)		December 31, 2011		December 31, 2011		December 31, December 3 2011 December 3 2010		December 31, December 31 2011 2010		December 31, December 31, D 2011 2010		December 31, December 3 2011 2010		December 31, December 31, December 2011 2010 2009		ber 31, 09
Current:																	
Federal	\$	63	\$	11	\$	0											
State		244		292		0											
Deferred:																	
Federal	(6	5,778)	3	,316	(9	,626)											
State		(561)		456	(1	,088)											
Total Income Tax Expense (Benefit)	\$(~	7,032)	\$4	,075	\$(10),714)											

A reconciliation of income tax expense (benefit) using the statutory U.S. income tax rate compared with actual income tax expense is as follows:

	Year Ended December 31, 2011 (in thousands)	Year Ended December 31, 2010 (in thousands)	Year Ended December 31, 2009 (in thousands)
Net income (loss) before noncontrolling interests and income			
taxes	\$(22,402)	\$10,111	\$(26,947)
Statutory U.S. income tax rate	35.0%	35.0%	35.0%
Tax expense (benefit) recognized using statutory U.S. income tax			
rate	\$ (7,841)	\$ 3,539	\$ (9,431)
Change in estimated future state rate	612	77	301
Permanent differences	176	33	7
Valuation Allowance	1,031	0	0
Other	110	(167)	(230)
Adjusted federal income tax expense (benefit)	\$ (5,912)	\$ 3,482	\$ (9,353)
State income tax expense (benefit)	(1,120)	593	(1,361)
Total income tax expense (benefit)	\$ (7,032)	\$ 4,075	\$(10,714)
Effective income tax rate	31.4%	40.3%	39.8%

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes. Deferred tax liabilities (assets) are comprised of the following at December 31, 2011 and 2010.

	December 31, 2011 (in thousands)	December 31, 2010 (in thousands)
Tax effects of temporary differences for:		
Current:		
Assets:		
G&G amortization	\$ 1,020	\$ 1,056
Valuation allowance	(175)	0
Other	329	6
Total current deferred tax assets	1,174	1,062
Liabilities:		
Unrealized gain on derivatives	(3,315)	(1,100)
Deferred gain on early hedge settlements	0	(1,870)
Total current deferred tax liabilities	(3,315)	(2,970)
Net total current deferred tax liability	(2,141)	(1,908)
Long-Term:		
Assets:		
Asset retirement obligation	7,704	7,030
Valuation allowance	(1,688)	0
Non-Cash compensation plans	2,095	1,780
Net operating loss carryforward	15,714	6,550
Organization costs	763	827
Other	375	503
Total long-term deferred tax assets	24,963	16,690
Liabilities:		
Unrealized gain on derivatives	(3,010)	0
Timing differences—tax partnerships	(1,818)	0
Book basis of oil and gas properties in excess of tax basis	(18,434)	(22,430)
Other	(58)	(190)
Total long-term deferred tax liabilities	(23,320)	(22,620)
Net total long-term deferred tax asset (liability)	\$ 1,643	\$ (5,930)

Management continuously evaluates the facts and circumstances representing positive and negative evidence in the determination of our ability to realize the deferred tax assets. These deferred tax assets consist primarily of net operating losses and deductible temporary differences. For the year ended December 31, 2011, management determined, based on positive and negative evidence examined and anticipated future taxable income, that it was appropriate to assign a valuation allowance for statutory depletion carryforwards and charitable contributions of approximately \$1.9 million. We have established a full valuation allowance against unused charitable contribution deductions, which in the absence of sufficient future taxable income, are likely to expire unused. Based on the expected patterns of reversal of all existing temporary differences, we have concluded that it is more likely than not that the remaining deferred tax assets will be realized. Prior to 2011, we have not required any valuation allowances.

Our management will continue, in future periods, to assess the likely realization of the deferred tax assets. The valuation allowance may change based on future changes in circumstances.

At December 31, 2011, we had available unused net operating loss carryforwards that may be applied against future taxable income that expire as follows:

Year of Expiration	Net Operating Loss Carryforwards (in thousands)
2027	\$ 27
2028	11,392
2029	2,160
2030	153
2031	25,781
Total	\$39,513
Statutory Tax Rate	39.77%
Tax Effected NOL	\$15,714

FASB ASC 740-10 sets forth a two-step process for evaluating tax positions. The first step is financial statement recognition of the tax position based on whether it is more likely than not that the position will be sustained upon examination by taxing authorities and resolution through related appeals or litigation, based on the technical merits of the case. FASB ASC 740-10 mandates certain assumptions in applying the more likely than not judgment, including the presupposition of an examination where the taxing authorities are fully informed of all relevant information for evaluation of the tax position. In other words, FASB ASC 740-10 precludes factoring the likelihood of a tax examination into the evaluation of the outcome so that the evaluation is to focus solely on the technical merits of the position.

Our management has concluded that, as of December 31, 2011, we have not taken any tax positions that would require disclosure as "unrecognized positions" and that no liability balance is required to offset any unsustainable positions. We did not have any accrued interest or penalties as of December 31, 2011 and 2010.

We file a consolidated federal income tax return and separate or consolidated state income tax returns in the United States Federal jurisdiction and in many state jurisdictions. We are subject to U.S. Federal income tax examinations and to various state tax examinations for periods after August 1, 2007.

13. EARNINGS PER COMMON SHARE

Basic income per common share is calculated based on the weighted average number of common shares outstanding at the end of the period, excluding restricted stock with performance-based vesting criteria. Diluted income per common share includes the speculative exercise of stock options and performance-based restricted stock which contain conditions that are not earnings or market based, given that the hypothetical effect is not anti-dilutive. For the year ending December 31, 2011, we excluded 603,064 stock options from the computation of diluted earnings per share because their effect would have been anti-dilutive. Stock options of 715,106 for the year ending December 31, 2010 were outstanding but not included in the computations of diluted net income per share because their effect would be anti-dilutive. Due to our net loss for the year ended December 31, 2009, we excluded all 873,837 of outstanding stock options because the effect would have been anti-dilutive to the computations (for additional information on our stock options and SARs, see Note 16, *Employee Benefit and Equity Plans*, to our Consolidated Financial Statements). The following table sets forth the computation of basic and diluted earnings per common share (in thousands except per share data):

	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009
Numerator (in thousands):			
Net Income (Loss) From Continuing Operations	\$ 18,088	\$ 8,058	\$(16,556)
Net Income (Loss) From Discontinued			
Operations	(33,457)	(2,022)	323
Net Income (Loss)	<u>\$(15,369)</u>	\$ 6,036	<u>\$(16,233)</u>
Denominator (in thousands):			
Weighted Average Common Shares Outstanding—			
Basic Effect of Dilutive Securities:	43,930	43,281	36,806
Employee Stock Options	95	112	0
Employee Performance-Based Restricted Stock			
Awards	451	277	0
Weighted Average Common Shares Outstanding—			
Diluted	44,476	43,670	36,806
Earnings per Common Share(a):			2
Basic—Net Income (Loss) From Continuing			
Operations	\$ 0.41	\$ 0.18	\$ (0.45)
Operations	(0.76)	(0.05)	0.01
—Net Income (Loss)	\$ (0.35)	\$ 0.13	\$ (0.44)
Diluted—Net Income (Loss) From Continuing			
Operations	\$ 0.41	\$ 0.18	\$ (0.45)
Operations	(0.76)	(0.05)	0.01
—Net Income (Loss)	\$ (0.35)	\$ 0.13	\$ (0.44)

⁽a) All earnings per share amounts are attributable to Rex common shareholders

14. CAPITAL STOCK

Currently, our common stock is traded on the NASDAQ Global Market under the trading symbol "REXX". We have authorized capital stock of 100,000,000 shares of common stock and 100,000 shares of preferred stock. In January 2010, we completed a public offering of 6,900,000 shares of common stock at an offering price of

\$12.25 per share. The net proceeds from the offering were approximately \$80.2 million, after deducting underwriting discounts, commissions and estimated offering expenses. We used a portion of the proceeds to repay outstanding borrowings under our Senior Credit Facility and used the remaining net proceeds to fund a portion of our capital expenditure program for 2010 and for other general corporate purposes. As of December 31, 2011 and 2010, we had 44,859,220 and 44,306,677 shares of common stock outstanding, respectively. For additional information see Note 25, *Subsequent Events*, to our Consolidated Financial Statements.

15. MAJOR CUSTOMERS

Approximately 91.6% of our oil and natural gas sales from continuing operations for the three-year period ended December 31, 2011, have been sold to five customers, with the production mix becoming more diversified each subsequent year. In 2009, approximately \$42.9 million, or 88.4%, of our commodity sales from continuing operations were to three customers, with \$41.4 million, or 85.3%, coming from a single customer. In 2010, approximately \$62.0 million, or 92.2%, of our commodity sales from continuing operations were derived from five customers, with the largest customer being responsible for approximately \$51.9 million, or 77.2%, of total commodity sales. For the year ended December 31, 2011, approximately \$103.6 million, or 92.6%, of our commodity sales from continuing operations were attributable to four customers with the largest single purchaser accounting for \$62.9 million, or 56.2%.

16. EMPLOYEE BENEFIT AND EQUITY PLANS

401(k) Plan

We sponsor a 401(k) Plan for eligible employees who have satisfied age and service requirements. Employees can make contributions to the plan up to allowable limits. Our contributions to the plan are discretionary. Our contributions to the plan attributable to continuing operations were approximately \$0.4 million, \$0.3 million and \$0.1 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Equity Plans

We recognize all share-based payments to employees, including grants of employee stock options, in the income statement based on their grant-date fair values, using prescribed option-pricing models where applicable. The fair value is expensed over the requisite service period of the individual grantees, which generally equals the vesting period. We report any benefits of tax deductions in excess of recognized compensation as a financing cash flow, rather than as an operating cash flow.

2007 Long-Term Incentive Plan

We have granted stock options, stock appreciation rights and restricted stock awards to various employees and non-employee directors under the terms of our 2007 Long-Term Incentive Plan (the "Plan"). The Plan is administered by the Compensation Committee of our board of directors (the "Compensation Committee"). Among the Compensation Committee's responsibilities are selecting participants to receive awards, determining the form, amount and other terms and conditions of awards, interpreting the provisions of the Plan or any award agreement and adopting such rules, forms, instruments and guidelines for administering the Plan as it deems necessary or proper. All actions, interpretations and determinations by the Compensation Committee are final and binding. The composition of the Compensation Committee is intended to permit the awards under the Plan to qualify for exemption under Rule 16b-3 of the Exchange Act. In addition, awards under the Plan, including annual incentive awards paid to executive officers subject to section 162(m) of the Code or covered employees, are intended to satisfy the requirements of section 162(m) to permit the deduction by us of the associated expenses for federal income tax purposes. The Compensation Committee has authorized the issuance of 3,079,470 shares under the Plan, with 929,635 and 1,408,494 still available as of December 31, 2011 and 2010, respectively.

All awards granted under the Plan have been issued at the prevailing market price at the time of the grant. All outstanding stock options have been awarded with five or ten year expiration at an exercise price equal to our closing price on the NASDAQ Global Market on the day of the award. A forfeiture rate based on a blended average of individual participant terminations and number of awards cancelled is used to estimate forfeitures prospectively.

Stock Options

During the year ended December 31, 2011, the Compensation Committee awarded nonqualified options to purchase a total of 90,074 shares of our common stock to three employees. During the year ended December 31, 2010, the Compensation Committee awarded nonqualified options to purchase a total of 111,174 shares of our common stock to three employees and five non-employee directors. The nonqualified stock options granted to our employees and non-employee directors during 2010 and 2011 have an exercise price equal to the closing price of our common stock on the NASDAQ Global Market on the date of the grant, and vest and become exercisable in one-third increments on the first, second or third anniversary of the grant date, provided that the option holder remains our employee or a director until that date. All options also provide that all unvested options vest and become immediately exercisable upon a "change in control" of us; as such term is defined in the Plan.

During fiscal year 2009, with the approval of our Compensation Committee, we modified the terms of certain stock option award agreements of three former employees located in our Southwest Region to partially vest options previously granted to such individuals. The options were partially vested pursuant to the terms of severance agreements entered into with the former employees as a result of the termination of their employment following the sale of our Southwest Region assets and the closing of our Midland, Texas office in March 2009. As modified, the options partially vested and became exercisable with respect to a total of 58,749 shares of our common stock which had an exercise price of \$9.99. We recognized approximately \$0.3 million in compensation expense related to these awards, \$0.2 million of which would have been recognized over the remaining life of the options had they not been accelerated.

Stock options represent the right to purchase shares of stock in the future at the fair market value of the stock on the date of grant. In the event that any outstanding award expires, is forfeited, cancelled or otherwise terminated without the issuance of shares of our common stock or is otherwise settled in cash, shares of our common stock allocable to such award, including the unexercised portion of such award, shall again be available for the purposes of the Plan. If any award is exercised by tendering shares of our common stock to us, either as full or partial payment, in connection with the exercise of such award under the Plan or to satisfy our withholding obligation with respect to an award, only the number of shares of our common stock issued net of such shares tendered will be deemed delivered for purposes of determining the maximum number of shares of our common stock then available for delivery under the Plan.

A summary of the stock option activity is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in thousands)
Options outstanding, December 31, 2008	993,700	\$13.81		
Granted	68,888	4.84		
Exercised	0	0		
Cancelled/Forfeited	(188,751)	12.06		
Options outstanding, December 31, 2009	873,837	\$13.41		
Granted	111,174	11.83		
Exercised	(22,000)	9.99		
Cancelled/Forfeited	(136,500)	18.18		
Options outstanding, December 31, 2010	826,511	\$12.50		
Granted	90,074	12.74		
Exercised	(139,682)	9.75		
Cancelled/Forfeited	(78,576)	13.75		
Options Outstanding, December 31, 2011	698,327	\$12.94	4.7	\$2,470
Options Exercisable, December 31, 2011	566,385	\$13.26	4.8	2,052

Stock-based compensation expense from continuing operations relating to stock options for the years ended December 31, 2011, 2010 and 2009 totaled \$0.7 million, \$1.0 million and \$1.0 million, respectively. The expense related to stock option grants was recorded on our Consolidated Statements of Operations under the heading of General and Administrative expense. The intrinsic value of stock options exercised for the years ended December 31, 2011, 2010 and 2009 was \$0.3 million, \$49,000 and \$0, respectively. The total tax benefit for the years ended December 31, 2011, 2010 and 2009 was \$0.1 million, \$19,000 and \$0, respectively.

The fair value of each option grant is estimated on the date of the grant using the Black-Scholes option-pricing model with the following assumptions:

	Year Ended December 31,			
	2011	2010	2009	
Expected dividend yield	0%	0%	0%	
Expected stock price volatility	74.7%	90%	72%	
Risk-free interest rate	0.63%	1.66%	1.87%	
Expected life of options (years)	4	4-6.5	4-6.5	

The dividend yield of zero is based on the fact that we have never paid cash dividends on common stock and have no present intention of doing so. Our expected historical volatility factor was determined by assessing the common stock trading history of eight publicly-traded oil and gas companies that we determined to be similar to us in ways such as their operating strategy, capital structure, production mix and volume and asset size in addition to our own historical volatility. The risk-free interest rate was determined by interpolating the average yield on a U.S. Treasury bond for a period approximately equal to the expected average life of the options. The average expected life has been determined using the "simplified method" in which the average expected life of the option is equal to the average of the term of the option and the vesting period. We elected to use the simplified method for determining the average expected life because we do not have a history on which to base estimates for the term to exercise of our granted stock options. We used an estimated forfeiture rate of 26.0% in 2011 for calculating stock-based compensation expense related to stock options and this rate is based on historical experience.

Based on the above assumptions, the weighted average estimated fair value of options granted during the years ended December 31, 2011, 2010 and 2009 was \$6.06 per share, \$6.74 per share and \$3.26 per share, respectively. The weighted average exercise price of options granted during 2011, 2010 and 2009 was \$12.78, \$11.83 and \$4.84 per share, respectively.

A summary of the status of our issued and outstanding stock options as of December 31, 2011 is as follows:

		Outstanding	Outstanding Exercisable		
Exercise Price	Number Outstanding at 12/31/11	Weighted- Average Remaining Contractual Life (Years)	Weighted- Average Exercise Price	Number Exercisable at 12/31/11	Weighted- Average Exercise Price
\$9.99	230,499	5.9	\$ 9.99	230,499	\$ 9.99
\$9.50	100,000	5.9	\$ 9.50	100,000	\$ 9.50
\$13.56	12,500	6.1	\$13.56	12,500	\$13.56
\$22.34	30,000	6.3	\$22.34	30,000	\$22.34
\$23.88	75,000	1.4	\$23.88	75,000	\$23.88
\$23.28	4,000	1.5	\$23.28	4,000	\$23.28
\$19.92	13,000	1.6	\$19.92	13,000	\$19.92
\$21.10	30,000	1.7	\$21.10	30,000	\$21.10
\$5.04	46,041	7.4	\$ 5.04	30,696	\$ 5.04
\$10.42	29,548	8.5	\$10.42	9,848	\$10.42
\$13.01	18,526	3.8	\$13.01	6,175	\$13.01
\$12.50	19,139	3.9	\$12.50	6,380	\$12.50
\$11.87	3,500	4.3	\$11.87	0	\$ 0
\$12.30	36,574	1.1	\$12.30	18,287	\$12.30
\$13.19	50,000	4.8	\$13.19	0	\$ 0
Total	698,327	$\overline{4.7}$	12.94	566,385	13.26

The weighted average remaining contractual term and the aggregate intrinsic value for options outstanding at December 31, 2011 were 4.7 years and \$2.5 million, respectively. The weighted average remaining contractual term and the aggregate intrinsic value for options exercisable at December 31, 2010 were 6.7 years and \$2.5 million, respectively. As of December 31, 2011, unrecognized compensation expense related to stock options totaled approximately \$0.5 million, which will be recognized over a weighted average period of 2.4 years.

Stock Appreciation Rights

During the year ended December 31, 2008, the Compensation Committee awarded 109,500 stock appreciation rights ("SARs") to five employees, and there were no awards made in 2009, 2010 or 2011. SARs represent the right to receive cash or shares of common stock in the future equivalent to the difference between the fair market value at the time of exercise and the strike price. The SARs have an exercise price equal to \$13.56, the closing price of our common stock on the NASDAQ Global Market on the date of the grant, and vest and become exercisable on the third anniversary of the grant date, provided that the holder remains our employee until that date. The SARs also provide that all unvested SARs vest and become immediately exercisable upon a "change in control" of us, as such term is defined in the Plan. The outstanding SARs issued as of December 31, 2011 may only be exercised for cash settlement. We incurred expense related to these awards of \$0, a credit of \$0.2 million and expense of \$0.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

			Outsta	nding		Exc	ercisable
Strike Price	Number of SARs Granted	SARs Forfeited or Cancelled	SARs Outstanding	Weighted- Average Remaining Contractual Life (Years)	Weighted- Average Strike Price	SARs	Weighted- Average Exercise Price
\$13.56	109,500	(89,000)	20,500	6.1	\$13.56	0	\$0
Total	109,500	(89,000)	20,500	$\frac{-}{6.1}$	\$13.56	$\frac{\overline{0}}{0}$	\$0

As of December 31, 2011, the aggregate intrinsic value of SARs outstanding was approximately \$25,000. There have been no SAR exercises to date. All of our SARs were granted in 2008 with grant date fair values of \$6.91 per share based on a weighted average exercise price of \$13.56 per share, expected annual dividends per share of 0.0%, expected life in years of 6.5, expected volatility of 45.1% and a risk-free interest rate of 4.1%. The dividend yield of zero is based on the fact that we have never paid cash dividends on common stock and have no present intention of doing so. Our expected historical volatility factor was determined by assessing the common stock trading history of eight publicly-traded oil and gas companies that we determined to be similar to us in ways such as their operating strategy, capital structure, production mix and volume and asset size. The risk-free interest rate was determined by interpolating the average yield on a U.S. Treasury bond for a period approximately equal to the expected average life of the SARs. The average expected life has been determined using the "simplified method" in which the average expected life of the SARs is equal to the average of the term of the SARs and the vesting period. We elected to use the simplified method for determining the average expected life because we do not have a history on which to base estimates for the term to exercise of our granted stock options. We do not use an estimated forfeiture rate as all awards are expected to vest and become exercisable.

Restricted Stock Awards

During the year ended December 31, 2011, the Compensation Committee issued 709,890 shares of restricted common stock to selected employees and non-employee directors. During the year ended December 31, 2010, the Compensation Committee issued 860,563 shares of restricted common stock to selected employees and non-employee directors. The shares granted in 2011 and 2010 are subject to time vesting and performance-based vesting. The shares will vest on the date on which the Compensation Committee certifies that the performance goals have been satisfied, provided that the recipient has been in continuous employment with us from the grant date through the third anniversary of the grant date. Restrictions on the transfer associated with vesting schedules were determined by the Compensation Committee on an individual award basis. The restricted common stock is valued at the closing price of our common stock on the NASDAQ Global Market on the date of the grant. Upon a "change in control" of us, as such term is defined in the Plan, all restrictions will immediately lapse for performance-based awards to varying degrees based on performance metrics at the time of the change in control. For awards that do not contain a performance-based condition, all restrictions immediately lapse upon a change in control. Compensation expense associated with the restricted stock award is recognized on a straight-line basis over the vesting period.

We recorded compensation expense related to restricted common stock awards of \$0.9 million, \$0.1 million and \$0.2 million for the years ended December 31, 2011, 2010 and 2009, respectively. As of December 31, 2011, total unrecognized compensation cost related to the restricted common stock grants was approximately \$3.3 million to be recognized over a weighted average of 2.5 years.

A summary of the restricted stock activity for the years ended December 31, 2011, 2010 and 2009 is as follows:

	Number of Shares	Weighted- Average Grant Date Fair Value
Restricted stock awards, as of January 1, 2009	20,000	\$23.00
Awards	261,850	2.05
Forfeitures	(33,750)	2.05
Restricted stock awards, as of December 31, 2009	248,100	\$ 3.74
Awards	860,563	12.07
Forfeitures	(293,698)	7.99
Restricted stock awards, as of December 31, 2010	814,965	\$11.01
Awards	755,816	13.07
Forfeitures	(342,955)	11.60
Restricted stock awards, as of December 31, 2011	1,227,826	\$12.11

17. IMPAIRMENT EXPENSE

For the years ended December 31, 2011, 2010 and 2009, we incurred impairment expense from continuing operations of approximately \$14.6 million, \$8.9 million and \$1.6 million, respectively. We continually monitor the carrying value of our oil and gas properties and make evaluations of their recoverability when circumstances arise that may contribute to impairment (for additional information see Note 2, Summary of Significant Accounting Policies, to our Consolidated Financial Statements). During 2011, we incurred approximately \$11.6 million of expense related to the impairment of proved conventional shallow natural gas wells in the Appalachian Basin. In addition to the impairment related to our conventional shallow natural gas properties, we incurred approximately \$1.4 million in impairment expense related to the expiration or surrender of undeveloped acreage and \$1.6 million in impairment expense related to a refrigeration plant in the Appalachian Basin which was formerly in use before the commencement of operations at our cryogenic gas processing plant in Butler County, Pennsylvania. With larger scale gas processing capabilities in the region there is no further value for the refrigeration plant. During 2010, we determined that the carrying values of two of our test wells in Clearfield County, Pennsylvania, which were in various stages of drilling and completion, and did not hold proved reserves, were not recoverable due to a lack of a sales outlet and no current plans by us to complete the wells for commercial production. The carrying value of these wells before impairment was approximately \$3.9 million. In addition, we incurred approximately \$2.3 million in impairment expense related to the expiration or surrender of undeveloped acreage. The impairment expense incurred during 2009 was primarily due to the expiration and surrender of undeveloped acreage.

18. SUSPENDED EXPLORATORY WELL COSTS

We capitalize the costs of exploratory wells if a well finds a sufficient quantity of reserves to justify its completion as a producing well and we are making sufficient progress towards assessing the reserves and the economic and operating viability of the project.

The following table reflects the net change in capitalized exploratory well costs, excluding those related to Assets Held for Sale on our Consolidated Balance Sheets for the years ended December 31, 2011, 2010 and 2009 (\$ in thousands):

	_	2011		2010	2009
Beginning Balance at January 1,	\$	1,637	\$	5,107	\$ 2,213
Additions to capitalized exploratory well costs pending the determination of estimated proved reserves	1	06.045		34,330	2.894
Divested wells	•	0		10,770)	0
Reclassification of wells, facilities, and equipment based on the determination of estimated proved reserves		(95,926)	•	23,016)	0
Capitalized exploratory well costs charged to expense		11.756		$\frac{(4,014)}{1,627}$	<u>0</u>
Ending Balance at December 31,		11,756		1,637	5,107
year or less	_((11,756)		(1,637)	(2,894)
Capitalized exploratory well costs for a period of greater than one year Number of projects that have exploratory well costs capitalized for a period of	\$	0	\$	0	\$ 2,213
more than one year		0		0	2

As of December 31, 2009 we had approximately \$2.2 million in capitalized exploratory well costs that were capitalized for a period greater than one year. These costs related to two wells in our Appalachian Basin. These wells ere in various stages of drilling and completion. On January 1, 2010, Williams became the operator of this joint venture area and does not currently have any plans to complete these wells and connect them into a sales line. While we still believe that these wells are capable of producing commercial quantities of natural gas, the lack of a sales line and plans to construct one give rise to substantial doubt about the carrying values of these wells. We subsequently expensed the carrying values of these wells in 2010, which is classified as Impairment Expense on our Consolidated Statement of Operations.

19. COSTS INCURRED IN OIL AND NATURAL GAS ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES (UNAUDITED)

Costs incurred in oil and natural gas property acquisitions and development are presented below and exclude any costs incurred related to Assets Held for Sale (in thousands):

	2011	2010	2009
Consolidated Entities:			
Acquisition of Properties			
Proved	\$ 9	\$ 53	\$ 39
Unproved	76,852	43,166	17,949
Exploration Costs	113,075	36,008	12,852
Development Costs(a)	61,920	24,825	12,211
Subtotal	251,856	104,052	43,051
Asset Retirement Obligations	316	186	255
Total Costs Incurred	\$252,172	\$104,238	\$43,306
Share of Equity Method Investments:			
Acquisition of Properties			
Proved	\$ 0	\$ 0	\$ 0
Unproved	0	0	0
Exploration Costs	0	0	0
Development Costs(a)	12,682	6,018	1,241
Total	\$ 12,682	\$ 6,018	\$ 1,241

⁽a) Includes Depreciation expense for support equipment and facilities.

20. OIL AND NATURAL GAS CAPITALIZED COSTS (UNAUDITED)

Our aggregate capitalized costs for natural gas and oil production activities with applicable accumulated depreciation, depletion and amortization are presented below and exclude any properties classified as Assets Held for Sale (in thousands):

	2011	2010
Consolidated Entities:		
Proven Oil and Natural Gas Properties	\$ 349,938	\$223,558
Pipelines and Support Equipment	30,926	31,610
Field Operation Vehicles and Other Equipment	9,489	7,471
Wells and Facilities in Progress	61,355	34,735
Unproven Properties	123,241	64,115
Total	574,949	361,489
Less Accumulated Depreciation and Depletion	(104,894)	(91,134)
Total	\$ 470,055	\$270,355
Share of Equity Method Investments:		
Pipelines and Support Equipment	\$ 25,344	\$ 10,841
Field Operation Vehicles and Other Equipment	36	29
Wells and Facilities in Progress	16,637	4,122
Total	42,017	14,992
Less Accumulated Depreciation and Depletion	(1,817)	(180)
Total	\$ 40,200	\$ 14,812

21. OIL AND NATURAL GAS RESERVE QUANTITIES (UNAUDITED)

Our independent engineers, Netherland, Sewell, and Associates, Inc. ("NSAI") evaluated all of our proved oil and natural gas reserves for the years ended December 31, 2011, 2010 and 2009. The technical persons responsible for preparing the estimates of our estimated proved reserves meet the requirements with regards to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Our independent third-party engineers do not own an interest in any of our properties and are not employed by us on a contingent basis. We emphasize that reserve estimates are inherently imprecise. Our oil and natural gas reserve estimates were generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates are expected to change, and such change could be material and occur in the near term as future information becomes available. All of our estimated proved reserves are located within the United States.

Proved oil and natural gas reserves represent the estimated quantities of oil and natural gas which geoscience and engineering data demonstrate with reasonable certainty will be economically producible - from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and governmental regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Proved developed oil and natural gas reserves are those expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are volumes expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Estimated proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing formation. Proved undeveloped reserves can only be assigned to acreage for which improved recovery technology is contemplated unless such techniques have been proven effective by actual tests in the area and in the same reservoir. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating they are scheduled to be drilled within five years, unless specific circumstances justify a longer time.

In December 2008, the SEC announced that it had approved revisions designed to modernize the oil and gas company reserves reporting requirements. See Note 2, *Summary of Significant Accounting Policies*, to our Consolidated Financial Statements. We adopted the rules effective December 31, 2009 and the rule changes, including those related to pricing and technology, are included in our reserves estimates.

Presented below is a summary of changes in estimated reserves of the oil and natural gas wells at December 31, 2011, 2010 and 2009.

		2011	
	Oil and NGLs (Bbls)	Natural Gas (Mcf)	Mcf Equivalents
Estimated Proved Reserves—Beginning of Period	12,342,828	127,621,835	201,678,803
Extensions and Discoveries	2,796,834	139,067,694	155,848,698
Revisions of Previous Estimates	1,060,941	16,515,036	22,880,682
Production(a)	(884,602)	(8,912,250)	(14,219,862)
Estimated Proved Reserves—End of Period	15,316,001	274,292,315	366,188,321

		2010	
	Oil and NGLs (Bbls)	Natural Gas (Mcf)	Mcf Equivalents
Estimated Proved Reserves—Beginning of Period	11,509,983	56,163,170	125,223,068
Sale of Reserves in Place	(369,758)	(12,251,612)	(14,470,160)
Extensions and Discoveries	3,461,768	93,229,532	114,000,140
Revisions of Previous Estimates	(1,542,033)	(6,511,733)	(15,763,931)
Production(a)	(717,132)	(3,007,522)	(7,310,314)
Estimated Proved Reserves—End of Period	12,342,828	127,621,835	201,678,803

(a) Gas production excludes certain production associated with gas sales contracts for which we do not recognize reserves. See Note 6, *Commitments and Contingencies*, to our Consolidated Financial Statements.

	2009			
	Oil and NGLs (Bbls)	Natural Gas (Mcf)	Mcf Equivalents	
Estimated Proved Reserves—Beginning of Period	5,993,626	30,019,477	65,981,233	
Purchases of Reserves in Place			_	
Extensions and Discoveries	940,883	18,422,999	24,068,297	
Revisions of Previous Estimates	5,302,862	9,231,194	41,048,366	
Production(a)	(727,388)	(1,510,500)	(5,874,828)	
Estimated Proved Reserves—End of Period	11,509,983	<u>56,163,170</u>	125,223,068	

(a) Oil production does not include approximately 372 barrels of oil produced attributable to a small oil field that was sold during 2009 and was not evaluated for purposes of reserves in 2008.

	Oil and NGLs (Bbls)	Natural Gas (Mcf)	Mcf Equivalent
Proved Developed Reserves			
December 31, 2011	10,399,620	110,853,300	173,251,020
December 31, 2010	8,799,105	32,477,226	85,271,856
December 31, 2009	8,623,430	16,161,494	67,902,074

Revisions. Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from developmental drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs.

We had significant revisions in our oil, NGL and natural gas reserves for the year ended December 31, 2011. The majority of our positive revision of estimated proved reserves occurred in our Marcellus Shale properties, where our average per well estimated ultimate recovery ("EUR") increased from 4.4 Bcfe to 5.3 Bcfe in our operated areas and from 3.0 Bcf to 4.2 Bcf in our non-operated areas. In total, our positive revisions in our Marcellus operations accounted for 84% of all revisions. Also impacting our revisions during 2011 was a change in the oil pricing from \$76.03 per barrel in 2010 to \$92.45 per barrel in 2011. We had significant revisions in our oil and NGL reserves of approximately 1.5 MMBOE for the year ended December 31, 2010, which were primarily due to a decrease in the pricing used for our NGLs from \$57.65 per barrel in 2009 to \$31.71 per barrel in 2010. The increase in our oil and NGL reserves of 5.3 MMBOE as of December 31, 2009 through revisions was primarily due to an increase in the price of oil used in the reserves estimates from \$41.00 per barrel in 2008 to \$57.65 per barrel in 2009. The increase in our natural gas reserves of 9.2 Bcfe as of December 31, 2009 through revisions was primarily due to a positive development and production history, which was partially offset by a decrease in the natural gas price used from \$5.71 in 2008 to \$3.87 in 2009.

Extensions, discoveries and other additions. These are additions to estimated proved reserves that result from (1) extension of the proved acreage of previously discovered reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with estimated proved reserves or of new reservoirs of estimated proved reserves in old fields.

We had significant extensions, discoveries and other additions for the year ended December 31, 2011, of 2.8 MMBOE of oil and NGLs and 139.1 Bcf of natural gas. These additions were primarily due to the additional proved undeveloped locations that were added to our proved reserve estimates that were a result of our continued drilling success in the Marcellus Shale. A portion of the extension and discoveries were booked as a result of successful efforts from exploration wells drilled in the Burkett and Utica Shales. In the Illinois Basin, we successfully booked estimated proved reserves as a result of our ASP pilot, which were classified as extensions and discoveries. For the year ended December 31, 2010 we had significant extensions, discoveries of 3.5 MMBOE for oil and NGLs and 93.2 Bcfe for natural gas. These additions were primarily due to the additional proved undeveloped locations that were added to our proved reserve estimates that were a result of our continued drilling success in the Marcellus Shale. Extensions, discoveries and other additions for the year ended December 31, 2009 of 0.9 MMBOE of oil and NGLs and 18.4 Bcfe of natural gas include increases in proved undeveloped locations as a result of our successful exploration efforts in the Marcellus Shale in conjunction with the change in the SEC's rules to allow producers in continuous accumulation plays to report additional undrilled locations beyond one offset on each side of a horizontal producing well.

22. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS (UNAUDITED)

FASB ASC 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to the estimated proved reserves. We followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying year-end prices and costs to estimate quantities of oil and natural gas to be produced. Actual future prices and costs may be materially higher or lower than the year-end prices and costs used. Estimates are made of quantities of estimated proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions. The resulting future net cash flows are reduced to present value amounts by applying a 10.0% annual discount factor.

The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved oil and natural gas reserves based on the standardized measure prescribed by FASB ASC 932 at December 31, 2011, 2010 and 2009 (\$ in thousands):

	2011	2010	2009
Future Cash Inflows	\$2,333,513(a)	\$1,335,068(b)	\$ 844,811(c)
Future Costs:	(000 000)	(7.40.04.4)	(2=0.242)
Production	(880,077)	(542,814)	(370,212)
Abandonment	(65,560)	(63,637)	(63,333)
Development	(251,821)	(152,965)	(86,819)
Net Future Cash Inflow Before Income Taxes	1,136,055	575,652	324,447
Future Income Tax Expense	(277,568)	(139,482)	(53,703)
Total Future Net Cash Flows Before 10.0% Discount	858,487	436,170	270,744
Less: Effect of a 10.0% Discount Factor	(444,552)	_(248,105)	(126,365)
Standardized Measure of Discounted Future Net Cash Flows	\$ 413,935	\$ 188,065	\$ 144,379

⁽a) Calculated using weighted average prices of \$4.55 per Mcf, \$92.45 per barrel of oil and \$46.34 per barrel of NGLs

- (b) Calculated using weighted average prices of \$4.57 per Mcf, \$76.03 per barrel of oil and \$31.71 per barrel of
- (c) Calculated using weighted average prices of \$3.87 per Mcf and \$57.65 per barrel of oil and NGLs

For purposes of consistency with 2011 calculations, we have revised certain amounts relating to changes in the standard measure of discounted future net cash flows with no effect to the previously reported period end measures. The principal sources of change in the standardized measure of discounted future net cash flows are as follows:

	2011	2010	2009
Standardized Measure—Beginning of Period	\$188,065	\$144,379	\$ 68,945
Revisions of Previous Estimates:			
Changes in Prices and Production Costs	29,223	33,083	35,466
Revisions in Quantities	40,525	(36,541)	90,475
Changes in Future Development Costs	(19,539)	(46,082)	32,431
Accretion of Discount and Timing of Future Cash Flows	25,218	17,438	6,895
Net Change in Income Tax	(42,875)	(34,117)	(30,000)
Purchase (Sale) of Reserves in Place	0	(10,438)	0
Plus Extensions, Discoveries, and Other Additions	159,047	44,135	5,715
Development Costs Incurred	61,290	24,825	12,211
Sales of Product—Net of Production Costs	(78,763)	(42,568)	(26,376)
Changes in Timing and Other	51,744	93,951	(51,383)
Standardized Measure—End of Period	\$413,935	\$188,065	\$144,379

23. RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Results of operations are equal to revenues, less (a) production costs, (b) impairment expenses, (c) exploration expenses, (d) DD&A expenses, and (e) income tax expense (benefit):

	2011	2010	2009
Consolidated Entities (in thousands): Revenues			
Oil and Natural Gas Sales	\$111,879	\$67,224	\$48,534
Expenses			
Production and Lease Operating Expense	33,116	24,656	22,157
Impairment Expense	14,631	8,863	1,625
Exploration Expense	2,507	2,578	2,080
Depletion, Depreciation, Amortization and Accretion	28,361	21,806	25,205
Total Costs	78,615	57,903	51,067
Pre-tax Operating Income (Loss)	33,264	9,321	(2,533)
Income Tax Expense (Benefit)(a)	10,445	3,850	(1,008)
Results of Operations for Oil and Gas Producing Activities(b)	\$ 22,819	\$ 5,471	<u>\$ (1,525)</u>
Share of Equity Method Investments (in thousands): Expenses			
Depletion, Depreciation, Amortization and Accretion	\$ 1,568	\$ 181	\$ 0
Total Costs	1,568	181	0
Pre-tax Operating Loss	(1,568)	(181)	0
Income Tax Benefit(a)	(519)	(75)	0
Results of Operation for Oil and Gas Producing Activities	\$ (1,049)	\$ (106)	\$ 0
Total Consolidated and Equity Method Investees Results of Operations for Oil			
and Gas Producing Activities	\$ 21,205	\$ 5,365	<u>\$(1,525)</u>

⁽a) Computed using the effective tax rate for each period: 31.4% in 2011; 41.3% in 2010 and; 39.8% in 2009.

24. LITIGATION

In September 2006, the United States Department of Justice ("DOJ"), the United States Environmental Protection Agency ("EPA") and the State of Illinois initiated an enforcement action against us seeking mandatory injunctive relief and potential civil penalties based on allegations that we (and various predecessor companies) were violating the Clean Air Act in connection with the release of hydrogen sulfide gas and volatile organic compounds ("VOC's") in the course of our oil producing operations near the towns of Bridgeport, Illinois and Petrolia, Illinois. In June 2007, the United States District Court for the Southern District of Illinois granted the United States' motion for approval and entry of a proposed consent decree, thereby resolving the enforcement action according to the terms described in the consent decree. The consent decree required us to take certain remedial actions to reduce hydrogen sulfide and VOC emissions and monitor the same. The consent decree did not require us to pay any civil fine or penalty, although it does provide for the possible imposition of specified daily fines and penalties for any violation of the terms and conditions of the consent decree.

In January 2010, we submitted certain proposed revisions to a Directed Inspection and Maintenance Plan previously implemented by us pursuant to the terms of the consent decree. In general, the proposed revisions update the plan to reflect changes in hydrogen sulfide control measures and procedures implemented in the field and changes in procedures for responding to resident complaints of hydrogen sulfide odors. The EPA, DOJ and Illinois EPA all approved these revisions.

Settlement Agreement—Illinois Class Action Litigation

We were a defendant in a class action lawsuit filed in the United States District Court for the Southern District of Illinois. This action was commenced in October 2006, by plaintiffs Julia Leib and Lisa Thompson, individually and as putative class representatives on behalf of all persons and non-governmental entities that own property or reside on property located in the towns of Bridgeport and Petrolia, Illinois. The complaint asserted several causes of action, including violation of the Resource Conservation and Recovery Act, Illinois Environmental Protection Act, negligence, private nuisance, trespass, and willful and wanton misconduct.

In December 2009, we entered into a Settlement Agreement and Release (the "Settlement Agreement") with Leib and Thompson, individually and on behalf of a certified class, to settle the class action lawsuit. Under the terms of the Settlement Agreement, without any admission of liability, we agreed to pay the class a total of \$1.9 million. Pursuant to the terms of a pollution liability policy, \$1.0 million of the settlement payment was funded by our insurance carrier. Pursuant to the Settlement Agreement, we also agreed to permanently plug four inactive oil wells. In return for the above consideration, each member of the class released all claims against us that in any way related to hydrogen sulfide or other environmental conditions in the class area that were the subject of, or could have been the subject of, the claims alleged in the class action lawsuit. In addition, each class member released any claims related to any future releases of hydrogen sulfide in the class area on the condition that we substantially comply with the terms and conditions of the consent decree describe above in "Illinois Basin EPA Consent Decree". The Settlement Agreement did not provide for a release of any potential individual claims of other class members since those claims were not the subject of the class action lawsuit. The Settlement Agreement became effective in April 2010.

Litigation Related to Proposed Oil and Gas Leases in Westmoreland and Clearfield Counties, Pennsylvania

In July 2009, we were named as defendants in a proposed class action lawsuit filed in the Court of Common Pleas of Westmoreland County, Pennsylvania (the "Snyder Case"). The named plaintiffs were five individuals who sued on behalf of themselves and all persons who are alleged to be similarly situated. The complaint in the Snyder Case generally asserted that a binding contract to lease oil and gas property was formed between the Company and each proposed class member when representatives of Duncan Land & Energy, Inc. ("Duncan Land"), a leasing agent that we engaged, presented a form of proposed oil and gas lease to each person, and each person signed the proposed oil and gas lease form and delivered the executed proposed lease to representatives of

Duncan Land. We rejected these leases and never signed them. The plaintiffs sought a judgment declaring the rights of the parties with respect to those proposed leases, as well as damages and other relief as may be established by plaintiffs at trial, together with interest, costs, expenses and attorneys' fees.

In May 2011, we entered into a Settlement Agreement with respect to these legal proceedings. In July 2011, the court approved the Settlement Agreement, pursuant to which we offered each eligible class member an oil and gas lease, in a form agreed to by the parties, with a prepaid rental of \$2,500 per acre for a five-year term with a 15% royalty. We also agreed to pay \$30,000 to plaintiffs' attorneys for the anticipated expenses of administration of the Settlement Agreement. Additionally, we deposited \$2.5 million into a fund for distribution to class members and for attorney's fees, costs and expenses of counsel for the class. The final order regarding the Settlement Agreement dismissed all claims against us with prejudice and without any admission of liability, and provided a release by all class members of all claims against us in connection with the litigation.

In June 2009, we were also named as a defendant in a lawsuit filed in the Court of Common Pleas of Clearfield County, Pennsylvania (the "Liegey Case"). The Liegey Case was brought by eight individuals involving oil and gas leasing activity in Clearfield County, Pennsylvania. The complaint in the Liegey Case asserts similar claims and requests for relief as those made in the Snyder Case described above. In June 2010, we settled the case and in July 2010, the court dismissed the case.

Litigation Related to Proposed Oil and Gas Leases in Clearfield County, Pennsylvania

In October 2011, we were named as defendants in a proposed class action lawsuit filed in the Court of Common Pleas of Clearfield County, Pennsylvania (the "Cardinale Case"). The named plaintiffs are two individuals who have sued on behalf of themselves and all persons who are alleged to be similarly situated. The complaint in the Cardinale Case generally asserts that a binding contract to lease oil and gas interests was formed between the Company and each proposed class member when representatives of Western Land Services, Inc. ("Western"), a leasing agent that we engaged, presented a form of proposed oil and gas lease and an order for payment to each person in 2008, and each person signed the proposed oil and gas lease form and order for payment and delivered the documents to representatives of Western. We rejected these leases and never signed them. The plaintiffs seek a judgment declaring the rights of the parties with respect to those proposed leases, as well as damages and other relief as may be established by plaintiffs at trial, together with interest, costs, expenses and attorneys' fees. The lawsuit is in the preliminary stages of discovery and we intend to vigorously defend against the claims. We are in the process of gathering data and executing our defense and we are unable to express an opinion with respect to the likelihood of an unfavorable outcome or provide an estimate of potential losses.

25. SUBSEQUENT EVENTS

Public Offering of Common Stock

On February 6, 2012, we completed an underwritten public offering of 8,050,000 shares of our common stock, which included 1,050,000 shares of common stock issued upon the full exercise of the underwriters' overallotment option, at a public offering price of \$9.25 per share. The net proceeds of the transaction are expected to be approximately \$70.6 million, after deducting underwriting discounts, commissions and estimated offering expense. We have used the proceeds of the offering to repay borrowings under our Senior Credit Facility.

26. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

The following tables set forth unaudited financial information on a quarterly basis for each of the last two years.

REX ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS(\$ and Shares in Thousands Except per Share Data)

		2	011	
	March	June	September	December
Revenues	\$23,147	\$29,023	\$ 30,755	\$31,681
Costs and Expenses	30,749	25,539	38,901	34,795
Net Income (Loss) From Continuing Operations	(3,533) (4,069)	7,797 (4,313)	12,666 (20,812)	1,149 (4,263)
Net Income (Loss)	(7,602)	3,484	(8,146)	(4,203) $(3,114)$
Net Income (Loss) Attributable to Noncontrolling Interests	(7,002) (102)	3,484	(8,140)	(5,114)
Net Income (Loss) Attributable to Rex Energy	\$(7,500)	\$ 3,440	\$ (8,190)	\$(3,121)
Income (Loss) per Common Share Attributable to Rex Common				
Shareholders:	¢ (0.00)	¢ 0.10	e 0.20	¢ 0.02
Basic—Continuing Operations	\$ (0.08) (0.09)	\$ 0.18 (0.10)	\$ 0.29 (0.47)	\$ 0.03 (0.10)
Basic—Net Loss	\$ (0.17)	\$ 0.08	\$ (0.18)	\$ (0.07)
Basic—Weighted Average Shares Outstanding	43,862	43,880	43,951	44,026
Diluted—Continuing Operations	\$ (0.08)	\$ 0.18	\$ 0.29	\$ 0.03
Diluted—Discontinued Operations	(0.09)	(0.10)	(0.47)	(0.10)
Diluted—Net Loss	\$ (0.17)	\$ 0.08	\$ (0.18)	\$ (0.07)
Diluted—Weighted Average Shares Outstanding	43,862	44,451	44,384	44,567
		20	010	
	March	June	010 September	December
Revenues	\$16,758	June \$15,686	September \$ 16,856	\$19,463
Costs and Expenses	\$16,758 14,766	June \$15,686 14,873	September	
Costs and Expenses	\$16,758 14,766 2,045	June \$15,686 14,873 1,228	\$ 16,856 7,316 9,867	\$19,463 26,025 (5,335)
Costs and Expenses	\$16,758 14,766 2,045 (53)	June \$15,686 14,873 1,228 (415)	September \$ 16,856	\$19,463 26,025 (5,335) (1,227)
Costs and Expenses	\$16,758 14,766 2,045	June \$15,686 14,873 1,228 (415) 813	September \$ 16,856	\$19,463 26,025 (5,335) (1,227) (6,562)
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992	June \$15,686 14,873 1,228 (415)	September \$ 16,856	\$19,463 26,025 (5,335) (1,227)
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992 (56)	June \$15,686 14,873 1,228 (415) 813 (64)	September \$ 16,856	\$19,463 26,025 (5,335) (1,227) (6,562) (45)
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048	June \$15,686 14,873 1,228 (415) 813 (64) \$ 877	September \$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$(6,517)
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048 \$ 0.05	\$15,686 14,873 1,228 (415) 813 (64) \$ 877 \$ 0.03	September \$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$(6,517) \$(0.12)
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048 \$ 0.05 0.00	\$15,686 14,873 1,228 (415) 813 (64) \$877 \$0.03 (0.01)	September \$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628 \$ 0.23 (0.01)	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$(6,517) \$(0.12) (0.03)
Costs and Expenses Net Income (Loss) From Continuing Operations Net Loss From Discontinued Operations Net Income (Loss) Net Loss Attributable to Noncontrolling Interests Net Income (Loss) Attributable to Rex Energy Income (Loss) per Common Share Attributable to Rex Common Shareholders: Basic—Continuing Operations Basic—Discontinued Operations Basic—Net Loss	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048 \$ 0.05 0.00 \$ 0.05	\$15,686 14,873 1,228 (415) 813 (64) \$877 \$0.03 (0.01) \$0.02	September \$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628 \$ 0.23 (0.01) \$ 0.22	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$(6,517) \$(0.12) (0.03) \$(0.15)
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048 \$ 0.05 0.00 \$ 0.05 42,106	\$15,686 14,873 1,228 (415) 813 (64) \$877 \$0.03 (0.01) \$0.02 43,710	September \$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628 \$ 0.23 (0.01) \$ 0.22 43,698	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$(6,517) \$(0.12) (0.03) \$(0.15) 43,586
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048 \$ 0.05 0.00 \$ 0.05 42,106 \$ 0.05	\$15,686 14,873 1,228 (415) 813 (64) \$877 \$0.03 (0.01) \$0.02 43,710 \$0.03	September \$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628 \$ 0.23 (0.01) \$ 0.22 43,698 \$ 0.23	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$ (6,517) \$ (0.12) (0.03) \$ (0.15) 43,586 \$ (0.12)
Costs and Expenses Net Income (Loss) From Continuing Operations Net Loss From Discontinued Operations Net Income (Loss) Net Loss Attributable to Noncontrolling Interests Net Income (Loss) Attributable to Rex Energy Income (Loss) per Common Share Attributable to Rex Common Shareholders: Basic—Continuing Operations Basic—Discontinued Operations Basic—Net Loss Basic—Weighted Average Shares Outstanding Diluted—Continuing Operations Diluted—Discontinued Operations	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048 \$ 0.05 0.00 \$ 0.05 42,106 \$ 0.05 0.00	\$15,686 14,873 1,228 (415) 813 (64) \$877 \$0.03 (0.01) \$0.02 43,710 \$0.03 (0.01)	\$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628 \$ 0.23 (0.01) \$ 0.22 43,698 \$ 0.23 (0.01)	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$(6,517) \$(0.12) (0.03) \$(0.15) 43,586 \$(0.12) (0.03)
Costs and Expenses	\$16,758 14,766 2,045 (53) 1,992 (56) \$ 2,048 \$ 0.05 0.00 \$ 0.05 42,106 \$ 0.05 0.00	\$15,686 14,873 1,228 (415) 813 (64) \$877 \$0.03 (0.01) \$0.02 43,710 \$0.03 (0.01)	\$ 16,856 7,316 9,867 (327) 9,540 (88) \$ 9,628 \$ 0.23 (0.01) \$ 0.22 43,698 \$ 0.23 (0.01)	\$19,463 26,025 (5,335) (1,227) (6,562) (45) \$(6,517) \$(0.12) (0.03) \$(0.15) 43,586 \$(0.12) (0.03)

	2009			
	March	June	September	December
Revenues	\$ 8,830	\$11,541	\$13,055	\$15,265
Costs and Expenses	10,179	20,978	14,241	19,861
Net Loss From Continuing Operations	(1,349)	(9,437)	(1,186)	(4,596)
Net Income From Discontinued Operations	323			
Net Loss	(1,026)	(9,437)	(1,186)	(4,596)
Net Loss Attributable to Noncontrolling Interests	_			(12)
Net Loss Attributable to Rex Energy	\$(1,026)	\$ (9,437)	\$(1,186)	\$ (4,584)
Earnings per Common Share Attributable to Rex Common Shareholders:				
Basic—Continuing Operations	\$ (0.04)	\$ (0.26)	\$ (0.03)	\$ (0.12)
Basic—Discontinued Operations	0.01			
Basic—Net Loss	\$ (0.03)	\$ (0.26)	\$ (0.03)	\$ (0.12)
Basic—Weighted Average Shares Outstanding	36,726	36,846	36,844	36,818
Diluted—Continuing Operations	\$ (0.04)	\$ (0.26)	\$ (0.03)	\$ (0.12)
Diluted—Discontinued Operations	0.01	_	_	_
Diluted—Net Loss	\$ (0.03)	\$ (0.26)	\$ (0.03)	\$ (0.12)
Diluted—Weighted Average Shares Outstanding	36,726	36,846	36,844	36,818

ITEM 9. CHANGE IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. We have established disclosure controls and procedures to ensure that material information relating to the company is made known to the officers who certify the financial statements and to other members of senior management and the audit committee of our board of directors. As of December 31, 2011, an evaluation was performed under the supervision and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer (the "CEO and CFO"), of the effectiveness of the design and operation of the our disclosure controls and procedures (as defined in Rules 13a-15(e), and 15d-15(e) under the Securities Exchange Act of 1934). An evaluation was conducted to ensure that information we are required to disclose in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms. Our CEO and CFO have concluded that our disclosure controls and procedures were effective as of the date of such evaluation.

Changes in Internal Control over Financial Reporting. No change to our internal control over financial reporting occurred during the year ended December 31, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting. Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f), and 15d-15(f) under the Securities Exchange Act of 1934). Management has used the framework set forth in the report entitled Internal Control—Integrated Framework published by the COSO of the Treadway Commission to evaluate the effectiveness of our internal control over financial reporting. Internal control over financial reporting refers to the process designed by, or under the supervision of, our CEO and CFO, and overseen by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, and includes those policies and procedures that:

- Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company;
- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of
 financial statements in accordance with general accepted accounting principles, and that receipts and
 expenditures of the company are being made only in accordance with authorizations of management
 and directors of the company; and
- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use
 or disposition of the company's assets that could have a material effect on the financial statements.

Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, however, neither internal control over financial reporting nor disclosure controls and procedures can provide absolute assurance of achieving financial reporting objectives because of their inherent limitations. Internal control over financial reporting and disclosure controls are processes that involve human diligence and compliance, and are subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting and disclosure controls also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented, detected or reported on a timely basis by internal control over financial reporting or disclosure controls. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design safeguards for these processes that will reduce, although may not eliminate, these risks.

Management has concluded that our internal controls over financial reporting and our disclosure controls and procedures were effective as of December 31, 2011. Management reviewed the results of their assessment with our Audit Committee. The effectiveness of our internal control over financial reporting as of December 31, 2011 has been audited by KPMG, LLP an independent registered public accounting firm, as stated in their report which is included in Item 8 of this Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

The Board of Directors Rex Energy Corporation:

We have audited Rex Energy and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Rex Energy Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of Rex Energy Corporation and subsidiaries as of December 31, 2011, and the related consolidated statements of operations, changes in noncontrolling interests and stockholders' equity (deficit), and cash flows for the year then ended, and our report dated March 15, 2012 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP Dallas, Texas March 15, 2012

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated by reference to such information as set forth in our definitive Proxy Statement (the "2012 Proxy Statement") for our 2012 annual meeting of stockholders. The 2012 Proxy statement will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement for the 2012 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement for the 2012 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement for the 2012 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to the 2012 Proxy Statement for the 2012 annual meeting of stockholders, which will be filed with the SEC not later than 120 days subsequent to December 31, 2011.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(a)(1) Financial Statements

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2009	75
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(a)(2) Financial Statement Schedules

All other schedules are omitted because they are not applicable, not required, or because the required information is included in the financial statements or related notes.

(a)(3) Exhibits.

- 2.1 Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
- 2.2 Form of Area One Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.2 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
- 2.3 Form of Area Two Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.3 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
- 2.4 Form of Area Three Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.4 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
- 2.5 Form of Area Four Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.5 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
- 2.6 Form of Parent Guaranty of Rex Energy Corporation attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.6 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
- 2.7 Form of Parent Guaranty of Sumitomo Corporation attached and made a part of the Participation and Exploration Agreement, dated August 31, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.7 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
- 2.8 First Amendment to Participation and Exploration Agreement, dated September 30, 2010, by and among Summit Discovery Resources II, LLC, Rex Energy I, LLC, R.E. Gas Development, LLC, joined therein by Rex Energy Operating Corp., and for the limited purposes set forth therein, Rex Energy Corporation and Sumitomo Corporation (incorporated by reference to Exhibit 2.1 to our Current Report on Form 8-K filed with the SEC on October 6, 2010).

Exhibit Number	Exhibit Title
3.1	Certificate of Incorporation of Rex Energy Corporation (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
3.2	Certificate of Amendment to Certificate of Incorporation of Rex Energy Corporation (incorporated by reference to Exhibit 3.2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
3.3	Amended and Restated Bylaws of Rex Energy Corporation (incorporated by reference to Exhibit 3.3 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
3.4	Amendment to Amended and Restated Bylaws of Rex Energy Corporation (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K as filed with the SEC on February 16, 2011).
4.1	Form of Specimen Common Stock Certificate of Rex Energy Corporation (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on June 11, 2007).
10.1+	Rex Energy Corporation 2007 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to the registrant's Registration Statement on Form S-1/A filed with the SEC on June 11, 2007).
10.2	Consent Decree (incorporated by reference to Exhibit 10.5 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
10.3	Independent Director Agreement with John A. Lombardi dated April 1, 2007 (incorporated by reference to Exhibit 10.6 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on April 27, 2007).
10.4	Summary of oral month-to-month agreement regarding use of airplane between Charlie Brown Air Corp. and Rex Energy Operating Corp. (incorporated by reference to Exhibit 10.13 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.5	First Amended and Restated Aircraft Joint Ownership and Management Agreement, dated June 21, 2007, between Charlie Brown Air Corp. and Charlie Brown II Limited Partnership (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to our Registration Statement on Form S-1 (File No. 333-142430) as filed with the SEC on July 6, 2007).
10.6	Credit Agreement, dated as of September 28, 2007, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, BNP Paribas, as Syndication Agent, Sovereign Bank, as Documentation Agent and The Lenders Party Thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on October 3, 2007).
10.7	Guaranty and Collateral Agreement, dated as of September 28, 2007, made by Rex Energy Corporation and each of the other grantors (as defined therein) in favor of KeyBank National Association, as Administrative Agent (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on October 3, 2007).
10.8	Independent Director Agreement by and between Rex Energy Corporation and John W. Higbee effective as of October 17, 2007 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on October 19, 2007).
10.9*	Summary of Rex Energy Corporation Non-Employee Director Compensation Program.

Exhibit Number	Exhibit Title
10.10+	Form of Nonqualified Stock Option Award Agreement for employee common stock option awards under Rex Energy 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.28 to our Annual Report on Form 10-K filed with the SEC on March 31, 2008).
10.11	Form of Nonqualified Stock Option Award Agreement for non-employee director common stock option awards under Rex Energy 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.29 to our Annual Report on Form 10-K filed with the SEC on March 31, 2008).
10.12+	Form of Stock Appreciation Right Award Agreement under Rex Energy 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.30 to our Annual Report on Form 10-K filed with the SEC on March 31, 2008).
10.13+	Form of Restricted Stock Award Agreement under Rex Energy 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q filed with the SEC on August 6, 2008).
10.14	First Amendment to Credit Agreement, effective as of April 14, 2008, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on April 18, 2008).
10.15	Purchase Agreement, dated December 23, 2008, by and between Rex Energy I, LLC and Adventure Exploration Partners, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on December 30, 2008).
10.16	Second Amendment to Credit Agreement, effective December 23, 2008, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on January 9, 2009).
10.17	Operating Agreement of Charlie Brown Air II, LLC dated as of June 26, 2008 (incorporated by reference to Exhibit 10.35 to our Annual Report on Form 10-K/A filed with the SEC on October 9, 2009).
10.18	Letter Agreement, dated as of March 9, 2009, by and between Rex Energy I, LL and Adventure Exploration Partners, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on March 13, 2009).
10.19	Third Amendment to Credit Agreement, effective as of April 20, 2009, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on April 27, 2009).
10.20	Participation and Exploration Agreement dated June 18, 2009 by and among Williams Production Company, LLC, Williams Production Appalachia, LLC, Rex Energy I, LLC and R.E. Gas Development, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on June 24, 2009).
10.21	Tax Partnership Agreement attached and made a part of the Participation and Exploration Agreement dated June 18, 2009 by and among Williams Production Company, LLC, Williams Production Appalachia, LLC, Rex Energy I, LLC and R.E. Gas Development, LLC (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on June 24, 2009).
10.22	Limited Liability Company Agreement of RW Gathering, LLC effective as of June 18, 2009 (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed with the SEC on June 24, 2009).

Exhibit Number	Exhibit Title
10.23	Settlement Agreement and Release by and between Julia Leib and Lisa Thompson, individually and on behalf of the certified class, on the one hand, and Rex Energy Operating Corp. and PennTex Resources Illinois, Inc., on the other hand, effective December 17, 2009 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on December 22, 2009).
10.24	Limited Liability Company Agreement of Keystone Midstream Services, LLC, dated December 21, 2009, by and among R.E. Gas Development, LLC, Stonehenge Energy Resources, L.P. and Keystone Midstream Services, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.25	Contribution Agreement, dated December 21, 2009, by and among R.E. Gas Development, LLC, Stonehenge Energy Resources, L.P. and Keystone Midstream Services, LLC (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.26	Gas Gathering, Compression and Processing Agreement, dated December 21, 2009, by and between R.E. Gas Development, LLC, Keystone Midstream Services, LLC and Rex Energy Corporation (incorporated by reference to Exhibit 10.3 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.27	Fourth Amendment to Credit Agreement, effective as of December 18, 2009, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto (incorporated by reference to Exhibit 10.4 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.28	Assumption Agreement effective as of December 18, 2009 made by R.E. Gas Development, LLC in favor of KeyBank National Association, as Administrative Agent, and the Lenders Party to the Credit Agreement (incorporated by reference to Exhibit 10.5 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.29	Supplement to Guaranty and Collateral Agreement effective as of December 18, 2009 made by Rex Energy Corporation in favor of KeyBank National Association, as Administrative Agent, and the Lenders Party to the Credit Agreement (incorporated by reference to Exhibit 10.6 to our Current Report on Form 8-K filed with the SEC on December 28, 2009).
10.30	Master Crude Purchase Agreement by and among certain direct and indirect wholly owned subsidiaries of Rex Energy Corporation and CountryMark Cooperative, dated December 30, 2009. (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on January 5, 2010).
10.31+	Form of Restricted Stock Award Agreement for employee restricted stock awards under Rex Energy 2007 Long-Term Incentive Plan (prior to December 2011) (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on March 31, 2010).
10.32*+	Form of Performance-Based Restricted Stock Award for employee restricted stock awards under Rex Energy 2007 Long Term Incentive Plan (first effective for awards granted in December 2011).
10.33*+	Form of Service Based Restricted Stock Award Agreement for employee restricted stock awards under Rex Energy 2007 Long-Term Incentive Plan (first effective for awards granted in December 2011).
10.34	Independent Director Agreement by and between Rex Energy Corporation and Eric L. Mattson effective as of April 30, 2010 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on April 30, 2010).

Exhibit Number	Exhibit Title
10.35	Purchase and Sale Agreement dated June 28, 2010 by and between Rex Energy Rockies, LLC and Duncan Oil Partners, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on July 7, 2010).
10.36	Fifth Amendment to Credit Agreement, effective as of December 18, 2009, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on September 3, 2010).
10.37	First Amendment to Limited Liability Company Agreement of Keystone Midstream Services, LLC, dated September 30, 3010, by and among Keystone Midstream Services, LLC, R.E. Gas Development, LLC, Stonehenge Energy Resources, L.P., and Summit Discovery Resources II, LLC (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed with the SEC on October 6, 2010).
10.38+	Employment Agreement by and between Patrick McKinney and Rex Energy Operating Corp. dated October 1, 2010 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on October 7, 2008).
10.39+	Employment Agreement by and between Thomas C. Stabley and Rex Energy Operating Corp. dated October 1, 2010 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on October 7, 2010).
10.40+	Employment Agreement by and between Daniel J. Churay and Rex Energy Operating Corp. dated November 1, 2010 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on November 3, 2010).
10.41	Confirmation No. 2 under Master Crude Purchase Agreement by and among certain direct and indirect wholly owned subsidiaries of Rex Energy Corporation and CountryMark Cooperative dated January 3, 2011 for period commencing on January 1, 2011 through December 31, 2011 (incorporated by reference to Exhibit 10.42 to our Annual Report on Form 10-K filed with the SEC on March 3, 2011) (Portions of this exhibit are subject to a request for confidential treatment and have been redacted and filed separately with the Securities and Exchange Commission).
10.42+	Separation Agreement by and between Timothy P. Beattie and Rex Energy Operating Corp. dated January 28, 2011 (incorporated by reference to Exhibit 10.43 to our Annual Report on Form 10-K filed with the SEC on March 3, 2011).
10.43+	Rex Energy Corporation Executive Change of Control Policy (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on February 16, 2011).
10.44*+	Rex Energy Corporation Executive Severance Policy.
10.45	Form of Non-Employee Director Restricted Stock Award/Phantom Stock Award Agreement under Rex Energy Corporation 2007 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to our Annual Report on Form 10-K filed with the SEC on March 3, 2011).
10.46+	Separation Agreement and Complete Release by and between Daniel J. Churay, Rex Energy Corporation and Rex Energy Operating Corporation dated June 9, 2011 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q as filed with the SEC on August 5, 2011).
10.47	Settlement Agreement by and among Rex Energy Corporation, Rex Energy I, LLC and certain landowners in Westmoreland County of the Commonwealth of Pennsylvania dated as of May 13, 2011 (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q as filed with the SEC on August 5, 2011) (Portions of this exhibit are subject to a request for confidential treatment and have been redacted and filed separately with the Securities and Exchange Commission).

Exhibit Number	Exhibit Title
10.48+	Employment Agreement by and between Jennifer McDonough, Rex Energy Corporation, and Rex Energy Operating Corporation effective April 25, 2011 (incorporated by reference to Exhibit 10.3 to our Quarterly Report on Form 10-Q as filed with the SEC on August 5, 2011).
10.49+	Letter Agreement by and between Thomas C. Stabley and Rex Energy Corporation dated October 10, 2011 (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K as filed with the SEC on October 11, 2011).
10.50+	Letter Agreement by and between Patrick M. McKinney and Rex Energy Corporation dated October 10, 2011 (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K as filed with the SEC on October 11, 2011).
10.51	Natural Gas Sales Agreement between R.E. Gas Development, LLC and BP Energy Company dated as of August 9, 2011 (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q as filed with the SEC on November 8, 2011).
10.52	Sixth Amendment to Credit Agreement, effective as of August 2, 2011, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q filed with the SEC on November 8, 2011).
10.53	Seventh Amendment to Credit Agreement, effective as of October 3, 2011, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q filed with the SEC on November 8, 2011).
10.54*	Second Lien Credit Agreement dated as of December 22, 2011 among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, UnionBanCal Equities, Inc. and SunTrust Bank, as Co-Documentation Agents and the Lenders Signatory Thereto.
10.55*	Guarantee and Second Lien Collateral Agreement dated as of December 22, 2011 among Rex Energy Corporation and each of the Grantors defined therein in favor of KeyBank National Association, as Administrative Agent.
10.56*	Eighth Amendment to Credit Agreement, effective as of December 22,2011, among Rex Energy Corporation, as Borrower, KeyBank National Association, as Administrative Agent, and The Lenders Signatory Thereto.
16.1	Letter from Malin, Bergquist & Company, LLP dated March 25, 2011 (incorporated by reference to Exhibit 16.1 to our Current Report on Form 8-K as filed with the SEC on March 25, 2011).
16.2	Letter from KPMG LLP dated March 25, 2011 (incorporated by reference to Exhibit 16.2 to our Current Report on Form 8-K as filed with the SEC on March 25, 2011).
21.1*	Subsidiaries of the Registrant.
23.1*	Consent of KPMG, LLP.
23.2*	Consent of Malin, Bergquist & Company, LLP.
23.3*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of Chief Executive Officer (Principal Executive Officer) pursuant to Section 302 of the Sarbanes-Oxley Act.

Exhibit Number	Exhibit Title
31.2*	Certification of Chief Financial Officer (Principal Financial and Principal Accounting Officer) pursuant to Section 302 of the Sarbanes-Oxley Act.
32.1*	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act.
99.1	Report of Netherland, Sewell & Associates, Inc. (incorporated by reference to Exhibit 99.2 to our Current Report on Form 8-K filed with the SEC on January 17, 2012).
101.INS**	XBRL Instance Document
101.SCH**	XBRL Taxonomy Extension Schema Document
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document

^{*} Filed herewith.

⁺ Indicates management contract or compensation plan or arrangement.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and gas industry terms used in this report:

Basin. A large natural depression on the earth's surface in which sediments accumulate.

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, of crude oil.

Bcf. Billion cubic feet, determined using the ratio of six Mcf of gas to one Bbl of crude oil, condensate or gas liquids.

Bopd. Barrels of oil per day.

Btu or British Thermal Unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The installation of permanent equipment for the production of oil or gas.

Development or Developmental well. A well drilled within the proved boundaries of an oil or gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses, taxes and the royalty burden.

Estimated proved reserves. Those quantities of oil and gas, which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations, prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geosciences and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geosciences, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geosciences, engineering or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Exploitation. A drilling or other project which may target proved or unproved reserves (such as probable or possible reserves), but generally is expected to have lower risk.

Exploration or Exploratory well. A well drilled to find and produce oil or gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

Field. An area consisting of either a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or *gross wells*. The total acres or wells, as the case may be, in which a working interest is owned.

Horizontal drilling. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well which has the ability to produce higher volumes than a vertical well drilled in the same formation.

Injection well or Injection. A well which is used to place liquids or gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

Lease operating expenses. The expenses of lifting oil or gas from a producing formation to the surface, and the transportation and marketing thereof, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, ad valorem taxes and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBOE. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet of natural gas.

Mcfd. One thousand cubic feet of natural gas per day.

MMBbls. One million barrels of oil or other liquid hydrocarbons.

MMBOE. One million barrels of oil equivalent.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of gas.

MMcfe. One million cubic feet equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil, condensate or gas liquids.

Net acres or net wells. The sum of the fractional working interests owned in gross acres or wells, as the case may be.

NYMEX. New York Mercantile Exchange.

PV-10 or present value of estimated future cash flows. An estimate of the present value of the estimated future cash flows from proved oil and gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future cash flows are discounted at an annual rate of 10%, in accordance with the Securities and Exchange Commission's practice, to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future cash flows are made using oil and gas prices and operating costs at the date indicated and held constant for the life of the reserves.

Primary recovery. The period of production in which oil and natural gas is produced from its reservoir through the wellbore without enhanced recovery technologies, such as water floods or ASP floods.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing reserves or *PDNP*. Proved developed reserves expected to be recovered from zones behind casing in existing wells.

Proved developed producing reserves or *PDP*. Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market.

Proved developed reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate

Proved undeveloped reserves or PUD. Reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Recompletion. The addition of production from another interval or formation in an existing wellbore.

Reserve life index. An index calculated by dividing year-end estimated proved reserves by the average production during the past year to estimate the number of years of remaining production.

Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Secondary recovery. An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Gas injection and waterflooding are examples of this technique.

Tertiary recovery. The third stage of hydrocarbon production during which sophisticated techniques that alter the original properties of the oil are used. Chemical flooding (including ASP flooding), miscible displacement and thermal flooding are examples of this technique.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or gas, regardless of whether or not such acreage contains estimated proved reserves.

Waterflooding. A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Workover. Operations on a producing well to restore or increase production.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Dated: March 15, 2012

REX ENERGY CORPORATION

By:	/s/ Thomas C. Stabley	
· · · · · · · · · · · · · · · · · · ·	Thomas C. Stabley	
	Chief Executive Officer and Interim	
	Chief Financial Officer	

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ Lance T. Shaner Lance T. Shaner	Chairman of the Board	March 15, 2012
/s/ THOMAS C. STABLEY Thomas C. Stabley	Chief Executive Officer, Interim Chief Financial Officer and Director (Principal Executive Officer)	March 15, 2012
/s/ ERIC L. MATTSON Eric L. Mattson	Director	March 15, 2012
/s/ JOHN W. HIGBEE John W. Higbee	Director	March 15, 2012
/s/ JOHN A. LOMBARDI John A. Lombardi	Director	March 15, 2012
/s/ JOHN J. ZAK John J. Zak	Director	March 15, 2012



In light of our drilling successes and added reserves, during the third quarter of 2011, our lenders increased our borrowing base by 50% over 2010 to \$240 million. With our continued positive operational results as support, our borrowing base was increased again in the fourth quarter to \$255 million, and we added a second credit facility of \$100 million to further enhance liquidity. This added borrowing availability, coupled with our increased cash flow from operations, has positioned us to execute on our strategic plans for 2012 while preserving our ability to quickly react to and exploit future opportunities that we believe will increase shareholder value.

For 2012, we are intensely focused on sustaining our growth, increasing our reserves, and strategically allocating our capital and resources to our liquids-rich prospects. We believe our acreage in Carroll County, Ohio is well positioned within the liquids window and we are looking forward to drilling and completing our first exploratory. Utica well there later this year. We plan to continue to expand our ASP project areas, and are actively designing a high-impact project on a 350 acre unit that has the potential to double the oil production of our Illinois Basin by 2015. We are also moving forward with our drilling program in the Butler County area with plans to drill 15 wells and complete 20 wells this year. With the help of our midstream partners, we are constructing a second cryogenic processing facility in Butler County, which will increase our processing capacity in the Butler County area to 90 MMcfe per day.

OUR PRIORITIES FOR 2012

- Continue to operate in a safe and environmentally responsible manner in all project areas
- Focus our capital and resources on the development of our core assets
- Execute our 2012 drilling and strategic plans
- •Together with our midstream partners, commission our second cryogenic facility and realize its full capacity as quickly as possible
- Drill and complete exploratory wells in Carroll County. Ohio prospective for the liquids-rich areas of the Utica Shale
- •Successfully expand ASP projects in the Illinois Basin with the goal to double current field production by 2015
- Maintain rigorous control of drilling and operating costs

Last year was a year of unprecedented growth and operational success for Rex Energy. We are excited about what 2012 holds for us, and are looking forward to exploiting the significant opportunities for growth that we've identified in our strategic plan. Although the current natural gas environment presents some challenges, we, the employees of Rex Energy remain steadfastly committed to fulfilling our goals and objectives for 2012. On behalf of the Board and the entire Rex Energy team, I want to thank you for your continued support of our Company. We know that you share our belief in the vast opportunities that natural gas and oil exploration present for our country and we appreciate your ongoing support as we contribute to America's energy future.

Sincerely,

Thomas C. Stabley Chief Executive Officer

COMPANY PARTICULARS

BOARD OF DIRECTORS

Lance T. Shaner, Chairman

Thomas C. Stabley, Director, Chief Executive Officer and Chief Financial Officer

John W. Higbee

Director and Chairman

of Compensation Committee John A. Lombardi,

Director and Chairman of Audit Committee

Eric L. Mattson, Director

John J. Zak, Director and Chairman of Nominating and Governance Committee

EXECUTIVE MANAGEMENT

Thomas C. Stabley. Chief Executive Officer and Chief Financial Officer

Patrick McKinney, President and Chief Operating Officer.

David Pratt, Senior Vice President, Exploration Manager

Scott Hodges

Senior Vice President, Land

Chris Marshall, Senior Vice President, Human Resources and Administration

Jennifer McDonough,

Vice President, General Counsel and Secretary

CORPORATE HEADQUARTERS

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INVESTOR RELATIONS

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INDEPENDENT AUDITORS

717 North Harwood Street, Suite 3100 Dallas, TX 75201 Telephone: (214) 840-2000 Fax: (214) 840-2297

TRANSFER AGENT

Computershare Investor Services P.O. Box 43078 Providence, Rhođe Island 02940-3078 Within USA, US temfones & Canada (800) 662 723 Outside USA, US térritories & Canada (781) 575-4238 www.computershare.com/investor

ANNUAL MEETING

May 10: 2012 at 11:00 a.m. Pittsburgh Marriott City Center 112 Washington Place Pitisburgh, PA 15219



Rex Energy Corporation

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